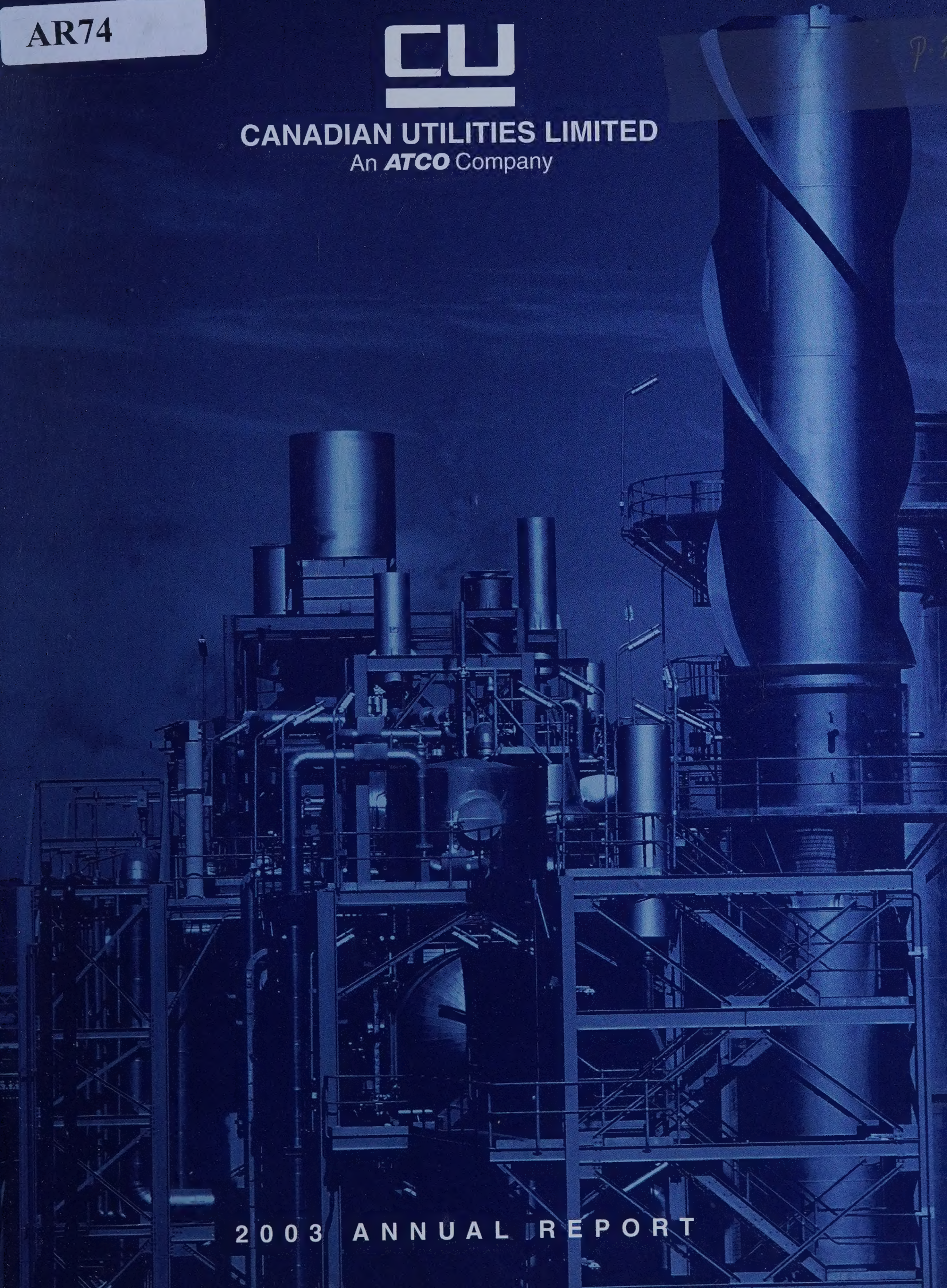
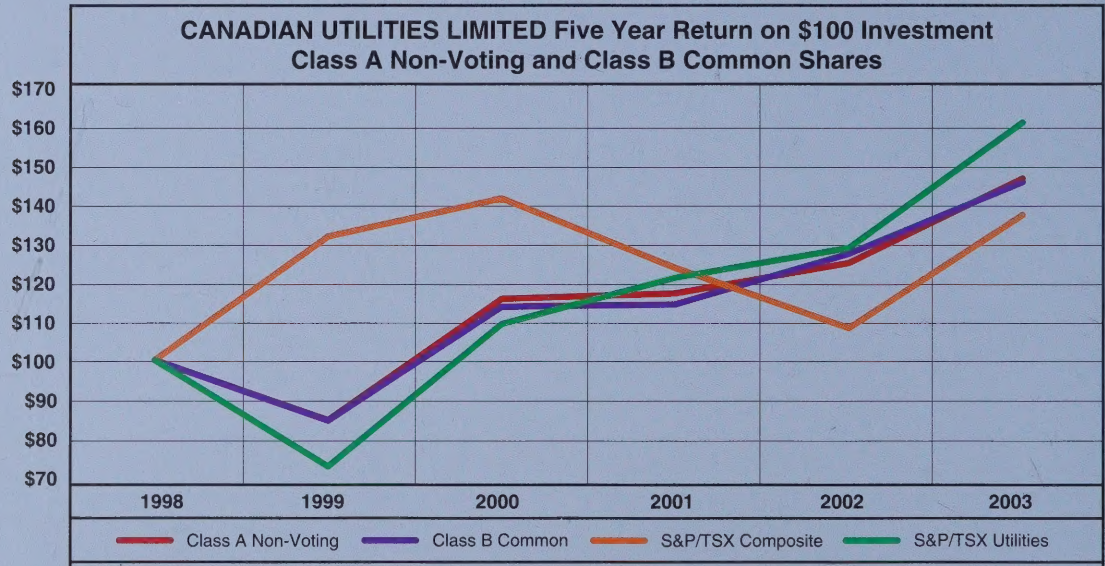
CANADIAN UTILITIES LIMITED

An ATCO Company



2003 ANNUAL REPORT

CANADIAN UTILITIES LIMITED is a premier corporation, Alberta based, with international operations well positioned for distinguished world class performance, growth, partnerships in the community and to pursue value creation strategies for sustainable and profitable growth.



	Compound Growth Rate	Cumulative Return
Class A Non-Voting	8.0%	$147
Class B Common	7.9%	$146
S&P/TSX Composite	6.5%	$137
S&P/TSX Utilities	10.0%	$161

Cumulative share owner return on the Class A Non-Voting and Class B Common shares of the Corporation vis-a-vis the S&P/TSX Composite and the S&P/TSX Utilities assuming a $100 investment made on December 31, 1998 and the reinvestment of dividends.

Table of Contents

Financial Highlights

Consolidated Annual Results

(millions of Canadian dollars, except per share data)	2003	2002
Financial		
Revenues	**3,742.6**	2,975.9
Earnings attributable to Class A and Class B shares	**259.3**	305(1)
Total assets	**6,070.5**	5,934.4
Class A and Class B share owners' equity	**1,951.6**	1,830.1
Cash flow from operations	**525.8**	504.6
Purchase of property, plant and equipment	**495.7**	569.8
Class A Non-Voting and Class B Common Share Data		
Earnings per share	**4.09**	4.81(1)
Diluted earnings per share	**4.07**	4.79(1)
Dividends paid per share	**2.04**	1.96
Equity per share	**30.79**	28.86
Shares outstanding	**63,383,635**	63,412,185
Weighted average shares outstanding	**63,389,192**	63,389,738

(1) The sale of the Viking-Kinsella property in 2002 increased earnings by $67.3 million, earnings per share by $1.06 and diluted earnings per share by $1.06.

Consolidated Quarterly Results (2)

(Unaudited)

(millions of Canadian dollars, except per share data)		Three Months Ended				
		March 31	June 30	Sept 30	Dec 31	Total
Revenues	**2003**	**1,372.2**	**797.5**	**622.6**	**950.3**	**3,742.6**
	2002	858.1	644.4	542.7	930.7	2,975.9
Earnings attributable to Class A and Class B shares	**2003**(3)	**85.8**	**43.4**	**43.4**	**86.7**	**259.3**
	2002	144.2	42.9	44.4	73.5	305.0
Earnings per Class A and Class B share	**2003**	**1.35**	**0.69**	**0.68**	**1.37**	**4.09**
	2002(3)	2.28	0.67	0.70	1.16	4.81
Diluted earnings per Class A and Class B share	**2003**	**1.34**	**0.69**	**0.68**	**1.36**	**4.07**
	2002(3)	2.27	0.67	0.70	1.15	4.79

(2) Because of seasonal fluctuations, particularly in the utility operations, quarterly earnings are not indicative of full year results.

(3) The sale of the Viking-Kinsella property in 2002 increased earnings for the three months ended March 31 and December 31 by $66.7 million and $0.6 million, respectively, earnings per share by $1.05 and $0.01, respectively, and diluted earnings per share by $1.05 and $0.01, respectively.

Chairman's Letter to Owners

TO THE OWNERS OF OUR CORPORATION

Canadian Utilities had record achievements in 2003 and your Directors have asked me to pass on to you the advice we give to our Executive Officers with respect to future growth strategies.

The dominating aim which we set before us . . . . is to have a sustainable premium company . . . . in every respect!

We do not seek maximum growth . . . . we seek sustainable optimum, profitable growth . . . . which is not quite the same thing.

Our financial balance sheet strength and the sustainability of our earnings over the long run take first place in your Directors' strategic deliberations . . . . and consequently, we counsel our Executives to husband their resources . . . . to grow internally with steady and moderate improvement in our position . . . . and when they do come into expansion . . . . to do so with their full strength of resources!

You can take great confidence in the capable people of our executive team and your Directors, who act with the full knowledge of the facts, and are working day in and day out on our future tactics and strategies. With respect to the important subject of Governance, may I refer you to our special elaboration on Page 5.

In the lives and experiences of your Directors, we have seen some very dangerous and dark times in the past and we counsel our Executives on the unexpected vicissitudes which may lie before us. Your Directors are universally concerned about the economies in which we operate. Let us see how the course of events develops, and let us not endeavour to speculate too audaciously on what we should be doing at any given time in the future.

When advantages come to our endeavours and when the proper opportunities and circumstances arise, you can be sure your Directors and Officers will act in your interests and your Company is well positioned to do so.

We wish to thank retiring Director, Bill Horton. A man of great wisdom and courage, Bill has provided us with dedicated service and excellence for 20 years. We are most fortunate that he has agreed to continue as a Director and Designated Audit Director ("DAD") of our Utilities sub-group.

Two new nominee Directors will stand for election at our AGM and they represent a diverse wealth of knowledge and experience which will be valuable in our deliberations.

With your agreement, we look forward to welcoming Michael Rayfield, Vice Chairman, Investment & Corporate Banking, BMO Nesbitt Burns; and James Simpson, Vice President of the Middle East & North Africa Business Development Inc. of ChevronTexaco Corporation.

On behalf of our Board, I would like to thank our people for their spirit and hard work. Also, to the owners of our shares, thank you for your loyalty and belief in our enterprise.

Respectfully submitted,

On behalf of the Board of Directors

R.D. Southern
Chairman

President's Letter

I write to you with great respect as I highlight our 2003 performance and our aspirations for 2004 and beyond.

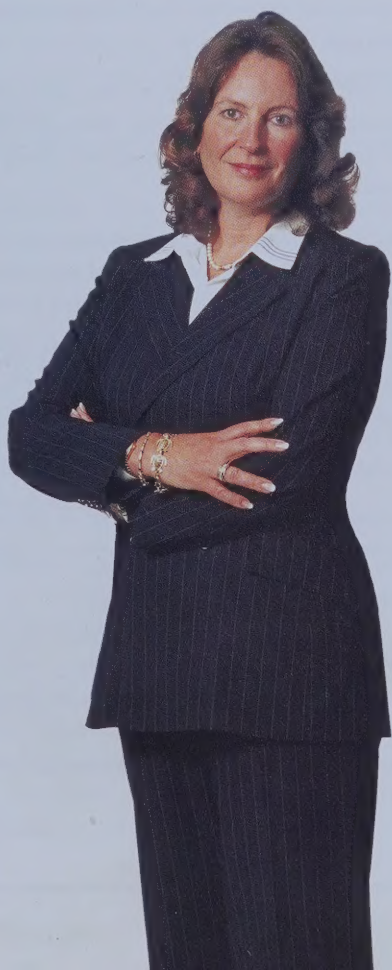
If you will recall, the economic environment of late 2002 and early 2003 was one of caution, fragility and, without question, there loomed the real possibility of recession or even deflation in the United States and Canada.

Therefore, our first objective for 2003 was to enhance our balance sheet. In April 2003, Canadian Utilities issued $150 million equity preferred shares to complement a $100 million medium-term note and $150 million equity preferred shares issued in late 2002, adding strength to already-existing strength. This funding, combined with cash from our asset monetization strategy and our operations, positions our balance sheet for maximum flexibility.

Your executive team's focus, with our Board of Directors oversight, regarding our cash is to ensure our ability to see us through any "rainy day" scenarios. Opportunities will emerge to advance your corporation in time, but currently, we believe it may well be prudent to have our cash on hand, given the growing uncertainty of the economies in which we operate.

As your President, and throughout my years with Canadian Utilities, I've always been struck by the external environment which brings pressure to produce short term results. Hence our executive team meets monthly to review and assess our performance. This internal process imposes discipline on us as managers and supports full accountability. However, you should know that I do not believe we should get too caught up in short term performance, which often entails the business "fad of the year" or "financial engineering", a belief your Board of Directors supports.

My purpose, and that of my colleagues, is to pursue well thought out strategies critical to our long term success. We realize human judgment is fallible, and it would be foolish to think that smooth courses will always be open to us. Still, the makeup and nature of the businesses we are in continues to give us confidence that we can deliver to our share owners sustainable growth now and into the future.



Our gas and electric utility operations are well positioned to continue capitalizing on the strong growth projected in the province of Alberta. New hookups, increased infrastructure demand, along with capital replacement and improvement initiatives will continue to provide our utilities with solid rate base growth.

A number of key regulatory and court decisions this past year have created greater momentum and impetus for our utility earnings. In particular, an Alberta Court of Appeal decision received in January 2004 clearly and decisively overturned a previous Alberta Energy and Utilities Board (EUB) decision that disallowed share owners a significant amount of the proceeds from the sale of a company owned asset. This landmark decision quite properly gives share owners virtually all benefits, less depreciation, as we dispose of assets no longer required for utility functions.

With the oversupply and market softening for the Power Generation Business Group in 2003, our focus has changed from development to concentrating on premier operations and maintenance and availability throughout our fleet of 18 generating plants. The newly built 260 megawatt (MW) Cory cogeneration facility in Saskatchewan, the 170 MW cogeneration facility at Muskeg River, the 170 MW cogeneration facility at Scotford, Alberta, and the 32 MW Oldman River Hydro project were all commissioned

in 2003 and added to our existing complement of 3,628 MW. The 580 MW gas-fired combined cycle generating plant at Brighton Beach in Windsor, Ontario, is the only plant that remains under construction in 2004 and commissioning is set for the latter half of 2004.

While we believe we have a strong portfolio of power plants in various markets that will provide significant earnings over the long term, it is fair to say that our Power Generation Group poses the greatest drag on current and medium term earnings due to oversupply and government uncertainty within the jurisdictions in which our plants operate.

Logistics and Energy Services delivered a year of nominal growth to the Group as they prepare to implement their northern strategy with our Aboriginal partners. We believe significant opportunities are available to this Group with the development of Voisey's Bay and the Mackenzie Valley Pipeline across northern Canada, as well as further development in Alaska.

The Technologies Business Group had an expansive year in 2003 as we finalized our customer information systems and call centres for "retail readiness" in the deregulated Alberta energy market for both natural gas and electricity.

Other initiatives we took in 2003 that will require further assessment and development in 2004 are:

- The careful examination of our operations' impact on the environment as well as developing options to mitigate and/or remediate environmental damage attributable to the Group;
- The preemptive analysis of pension and benefits programs for our employees;
- Ongoing attention to our method of operating with the objective of continuously improving our transparency, accountability and the clarity of our business plans;
- Putting the infrastructure in place to meet, fulfill and, where possible, exceed new accounting rules and Canadian Securities Administrators' requirements.

We believe these top-down driven initiatives will serve to enhance Canadian Utilities' position as a premier Canadian corporation, delivering dependable earnings to the people who own our shares, and confidence in how our enterprise is managed and governed.

We are probably a year or two, perhaps even a "business cycle" away from meaningful value added opportunities. Therefore, it is my hope that share owners join us with patience and steady nerves as we seek the best ways to achieve our growth while maintaining our strong balance sheet which, at present, gives Canadian Utilities the 'industry' leading credit rating.

Unquestionably, within certain horizons, we have the financial resources to execute a long term investment program but share owners should understand that our investments will depend on economic and market conditions — as well as — public policy setting that maintains a competitive and level playing field.

I believe we performed well in 2003, delivering record earnings from ongoing operations of $259 million. Our regular common dividends have also increased for the 31st consecutive year and our normal course operations expect that capital expenditures for 2004 will approach the same level — $500 million — as invested in 2003.

We have every reason to be proud of our past accomplishments and I can assure you of our strength going forward.

Your executive team has a unity of purpose. Our resolve will allow us to march from strength to strength, tackle each challenge as it comes and continue to give our share owners the sustainable growth you have come to expect.

Sincerely,

N.C. South

N.C. Southern
President and Chief Executive Officer

Corporate Governance

Canadian Utilities Limited has developed an effective system of corporate governance that has evolved and matured to meet the challenging requirements of providing comprehensive oversight to an organization with a diverse number of business groups and distinct principal operating subsidiaries.

Over the years, Canadian Utilities Limited has developed and implemented policies and procedures that are only now becoming required for other corporations.

In anticipation of CEO and CFO Financial Certifications, which become mandatory in the first quarter of 2004, we implemented financial certifications within our principal operating subsidiaries in the second quarter of 2003.

Certification requirements relating to internal controls and to disclosure controls and procedures will be required in 2005. A senior management team, assisted by independent professionals, is charged with completion of this project.

We have moved to strengthen the independence of your External Auditor. A new Audit and Non-Audit Services Policy has been approved which requires your Audit Committee to approve all services provided by your External Auditor. In the coming year, we will also be reviewing recently released Canadian Securities Administrators recommendations on new corporate governance and disclosure practices.

Canadian Utilities Limited strongly believes in fully engaging our Boards of Directors in all aspects of our governance process. Their diligence and extensive expertise are core to our ability to deliver differentiating performance in our enterprises.

We believe our method of operating and our transparent governance and communication are integral to the achievement of current results and the progressive record of sustainable growth that is the hallmark of our group of companies.

Key elements of this system of corporate governance are the oversight and diligence provided by the Boards of Directors of the business groups, Lead Directors, and the Governance — Nomination, Succession and Compensation Committee and the Audit, Risk Review and Pension Fund committees.

It is important for prospective share owners to understand Canadian Utilities Limited is controlled by ATCO Ltd., which in turn is a diversified Group of Companies principally controlled by family held Sentgraf Enterprises Ltd. We believe the principal share owner provides the corporation with standards and ethics that are the hallmark of ATCO Group's method of operating, allowing for a number of unique business attributes.

1. The Corporation is driven by leaders who, through true mutual transparency, commitment and loyalty, develop effective working teams;
2. The leaders seek a relentless pursuit of "before the fact" strategies — demonstrating pre-emptive vision and management, resulting in an ability to create value and growth over a long term as demonstrated by 14 consecutive years of earnings growth;
3. The people of the Corporation are energized by an extraordinarily intense spirit to create a performance-driven environment;
4. They are aligned by a simple structure with a firm grip on the plan;
5. Based on world class skills, especially in its people processes; the Corporation selects the best of the best for their situational leadership style of management.

Of particular note is that the Office of the Chairman, which is comprised of family leaders, senior management and the Managing Directors, often penetrate to deep levels in the organization and do so more frequently when times are tough. This makes them more personally effective and allows for faster, less filtered answers and decisions.

Directors, officers and the people of the company share with the family leaders a common spirit — "the ATCO heart & mind" — where people throughout the organization have an understanding of what it takes to make the businesses more successful and results in a very high level of information transparency in the Office of the Chairman. Critical ethical and commercial decisions are enhanced, not diminished, by family leadership supported and challenged by tried and true, world-class executives and Directors.

It is incumbent upon each principal operating subsidiary's president and management to keep the Office of the Chairman and Boards of Directors fully informed and to assure them that their expectations, based on capital and project approvals, will be met and the return on investment goals will be achieved.

R.D. Southern, Chairman of the Board, describes his pivotal role of fully engaging the Boards of Directors by creating:

1. freedom of expression, without limitation, by individual Directors,
2. a Board of Directors with great and varied experience,
3. a Board that functions as a unified, informed, judicious body.

The relationship between Directors, the Office of the Chairman and principal operating subsidiaries has been designed for:

- unusual transparency
- situational leadership
- extraordinary teamwork.

The system ensures there can be no devastating surprises from management.

The Board understands that the marketplace is a continuum. Reputation is all-important, both for the family and the Corporation. It defines them, the management and the employees, collectively, as being people of their word. The Board preemptively strives for excellence to ensure the company stays ahead of the competition — in both its operations and governance processes.

Directors' and senior officers' strategy conferences have taken place each and every year since 1981, with our 23rd conference held in April, 2003. The conference is the beginning of the business planning process where the overall strategies for growth, operationally and financially, are discussed and evaluated over the course of four days of presentations, plenary sessions and Directors' recommendations.

Governance, nomination, compensation and succession are thoroughly addressed by the Governance Committee (GOCOM) in dedicated, multi-day sessions in June and November. Ad-hoc meetings are also held throughout the year.

GOCOM is chaired by a Lead Director and is comprised of the Board's most senior and experienced Directors. The Chief Executive Officer and the Chairman attend GOCOM meetings as ex-officio members, but in-camera time is also taken by the committee. Initially formed in 1991, GOCOM recommends to the Board of Directors all executive appointments and performance based compensation, which places considerable emphasis on financial results.

Demonstrating leadership, GOCOM has made many innovative recommendations that has led to:

1. the appointment of Lead Directors and,
2. the development and implementation of Designated Audit Directors — appropriately referred to as "DADs" — an oversight program that calls on the strengths and experience of Directors in various industry sectors.

Each DAD is responsible for meeting on a quarterly basis with management, internal and external auditors and reviewing the financial statements and operating results of their assigned principal operating subsidiaries and reporting their findings to the Audit Committee. In addition, DADs attend each of the principal operating subsidiaries' Risk Management Committee meetings and report their findings to the Risk Review Committee.

Board meetings are held quarterly, and are well attended by all Directors. Board meetings are lengthy with deliberations often lasting a full day because of the quality of intensive discussion, due diligence and debate. The Board has the prerogative, the duty and the freedom to independently decide project approvals, financings, entry into new jurisdictions and material contracts.

There are four business groups, each comprised of a number of principal operating subsidiaries reporting to a Managing Director. Each business group also has a Board of Directors with a level of authority appropriate to the business group size and nature of the operations that is responsible for authorizing and approving the annual business plans, material contracts, strategic transactions, financings and major capital expenditures for each principal operating subsidiary within the business group. These boards meet three times per year.

In 2003, Canadian Utilities' Directors met nine times as a Board and the Audit, Risk Review, GOCOM and Pension Fund committees collectively met 13 times throughout the year.

A large commitment of time, interest, expertise and dedication was asked of and given by your Directors in 2003. In return, they focused on delivering quality governance and the excellence Canadian Utilities and their share owners expect from their businesses.

Financial Overview

Our balance sheet is well positioned for maximum flexibility with the issue of medium-term notes and equity preferred shares in 2002 and 2003, combined with cash from operations.

J.A. (James) Campbell
Senior Vice President, Finance
and Chief Financial Officer

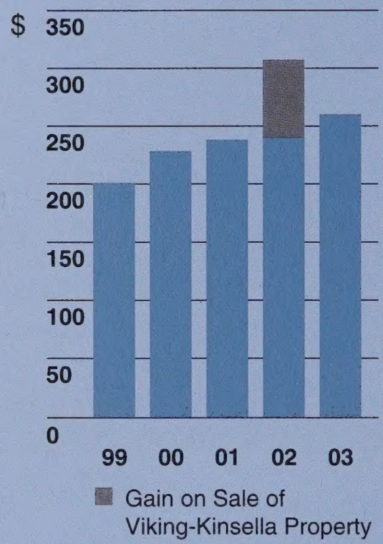
J.A. (James) Campbell

Financial Achievements in 2003

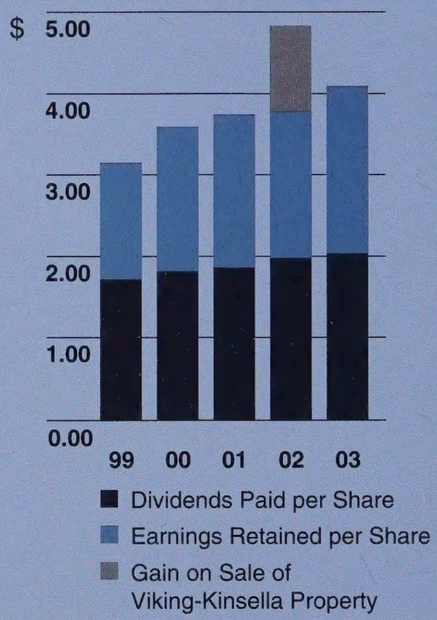
- Earnings per share increased to $4.09 from $3.75 in 2002, excluding the gain on sale of the Viking-Kinsella property ($1.06 per share) — the 14th consecutive year of increased earnings per share, excluding the gain on sale of the Viking-Kinsella property in 2002. 2002 earnings per share in total were $4.81.
- Dividends paid per Class A and Class B share increased by $0.08 to $2.04 from $1.96 in 2002 — dividends have increased each year since 1972 — 31 years!
- Earnings increased by $21.6 million to $259.3 million in 2003 compared to $237.7 million in 2002, excluding the gain on sale of the Viking-Kinsella property ($67.3 million). 2002 earnings in total were $305.0 million.
- Cash flow from operations increased by $21.2 million to $525.8 million.
- Total assets increased by $137 million to $6.071 billion compared to $5.934 billion in 2002.
- Capital expenditures were $496 million in 2003 compared to $570 million in 2002. Over the previous five years, capital expenditures averaged $524 million per year.
- Long term debt decreased by $112 million to $1.805 billion.
- Non-recourse long term debt decreased by $15 million to $852 million.
- Equity preferred shares increased by $150 million to $637 million.
- Share owners' equity increased by $122 million to $1.952 billion compared to $1.830 billion in 2002.
- Return on common equity was 13.7% compared to 17.6% in 2002.
- Financing activities in 2003 included the issue of $150 million of 6.0% equity preferred shares.
- CU redeemed $60 million of 7.25% debentures and $79 million of other debt in 2003 and issued $25 million of other debt in 2003.
- Non-recourse long term debt of $41 million was issued in 2003 for the Brighton Beach Power Project, while CU redeemed $38 million of non-recourse long-term debt in 2003.

Financial Overview

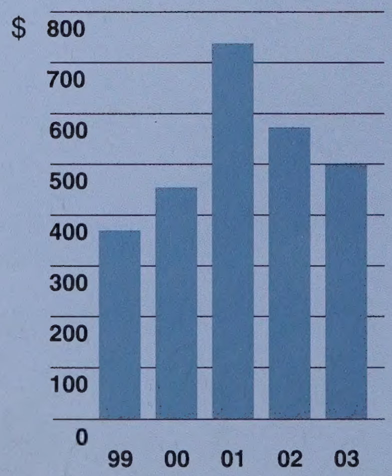
Earnings Attributable to Class A and Class B Shares
(millions of dollars)



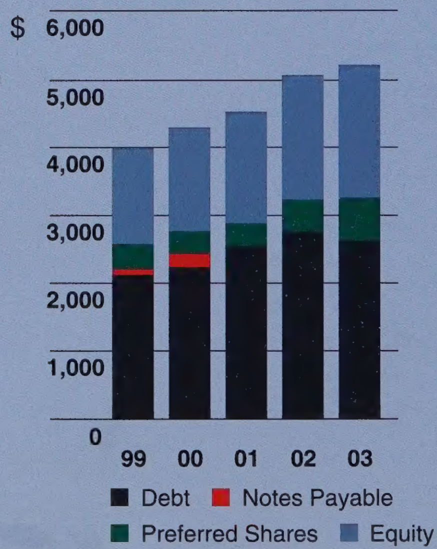
Earnings Per Class A and Class B Share
(dollars)



Purchase of Property, Plant and Equipment
(millions of dollars)



Capitalization
(millions of dollars)



Business Groups

CANADIAN UTILITIES LIMITED, part of the ATCO GROUP, is a premier Alberta based, Canadian Corporation, with a worldwide organization of companies and 6,000 employees actively engaged in Utilities, Logistics & Energy Services, Technologies, and Power Generation.

(1) Subsidiaries of CU Inc., a subsidiary of Canadian Utilities Limited.

Utilities Group

Photo: Built in just four months across the challenging terrain of north-eastern Alberta, ATCO Electric's Muskeg River transmission line is a key component of Alberta's robust economy delivering electricity over a 240 KV line to the high growth area of Fort McMurray and the large industrial customers such as Syncrude, Suncor and Shell.

Alberta's robust population growth, continuing deregulation of the energy industry and customer demand for timely, accurate energy consumption and conservation information formed the backdrop for the Utilities Group operations in 2003.

Photo: ATCO Gas added 25,800 new customers in 2003, the highest number of customer additions in over a decade. Installing new service line to provide customers with safe, reliable natural gas delivery is our core competency.

Meeting the complexities of Alberta's deregulated marketplace was of primary importance to the 2,900 employees of ATCO Gas and ATCO Electric who also prepared for the regulatory and operational changes required to complete the sale of the energy supply business to Direct Energy Regulated Services. The sale, announced in principle in December 2002, remains conditional on the successful satisfaction of regulatory, legislative and business conditions, some of which have since been met. The Alberta Energy and Utilities Board (EUB) approved the transfer in a December decision following a rigorous, eight-month public hearing process.

Key to the successful conclusion of an agreement with Direct Energy were several major regulatory revisions in 2003 to align the regulatory framework governing Alberta's natural gas industry and electricity industry. Amendments in the Electric Utilities Act and the Gas Utilities Act now provide customers with the convenience of one utility service bill combining both energy supply and energy delivery charges, a choice throughout the province between regulated or competitive rate energy service and the assurance of energy delivery rates that continue to be regulated.

ATCO Gas, ATCO Electric and ATCO Pipelines along with seven other Alberta energy delivery utilities are participating in a regulatory process to create a generic methodology to determine rate of return and common equity. The EUB will decide on capital structure and rate of return toward the end of 2004.

In 2004, ATCO Gas and ATCO Electric renewed their focus as energy delivery service companies with expertise in building and maintaining safe, reliable delivery systems for Alberta energy customers.

Construction investment for both utility companies hit near-record levels in 2003 as Alberta's robust economic growth served to increase new energy demand across all service sectors.

In keeping with the focus on delivering energy to Albertans, both ATCO Gas and ATCO Electric are exploring emerging technologies that promise to provide customers with greater control over their energy use with minimal impact to the environment.

ATCO Gas and ATCO Electric renewed their focus as energy delivery companies with expertise in building and maintaining safe, reliable delivery systems for Alberta energy customers.

UTILITIES

- ATCO Electric Ltd.
  - Norven Holdings Inc.
    - Northland Utilities Enterprises Ltd.
      - Northland Utilities (NWT) Limited
      - Northland Utilities (Yellowknife) Limited
  - The Yukon Electrical Company Limited
- ATCO Gas and Pipelines Ltd.
  - ATCO Gas (division)
- CU Water Limited
- ATCO Utility Services Ltd.

ATCO Gas invested $1.2 million to develop new research to determine viable commercial applications for power generated by Canada's first high voltage, fully operational fuel cell. In partnership with federal and provincial government agencies and the Northern Alberta Institute of Technology (NAIT), the $3.25 million project explores the potential of fuel cell production of environmentally friendly heat and power. Fuel cells, which work like a battery that does not need recharging, produce energy by combining hydrogen and oxygen. The most economical way to produce hydrogen is by using natural gas.

ATCO Electric is participating in a federal government "pay as you go" electric meter pilot program to provide customers and the company experience with a smart card metering system allowing customers to purchase the energy before they use it. Operating along the same principle as paying for car fuel before you use it, the project provides customers real time information of their energy consumption. The "pay as you go" meters are currently in use in Ontario and Arizona and are used throughout Europe for a variety of utilities.

In 2003, both ATCO Gas and ATCO Electric provided monthly meter reading service to the majority of its customers. Monthly meter reading provides both customers and energy retailers with more accurate billing information.

ATCO EnergySense saw an unprecedented 345% increase in demand for home energy audits in 2003 over 2002, as a result of the federal government's $73 million EnerGuide For Houses Retrofit Incentive. The program, which provides grants to homeowners who show they have increased their home's energy efficiency, requires customers to first have an EnerGuide for Houses (EGH) evaluation. ATCO EnergySense won the federal government contract to provide this service to Alberta in October 2001. The increase in consumer demand resulted in 7,833 EGH evaluations in 2003, the hiring of 30 additional EGH evaluators and improved ability to deliver 4,000 evaluations a month. Consumer interest in the program continues to be very high in 2004.

The ATCO Blue Flame Kitchen's 'Everyday Delicious' and 'Holiday Collection' cookbooks achieved record sales and their home economists handled over 55,000 telephone inquiries offering professional, respected and reliable advice on everyday living.

ATCO GAS

Capital expenditures reached a record $141.0 million in 2003 with signs of continued growth early in 2004. An additional 25,800 customers, the highest number of customer additions since 1982, were added to the ATCO Gas delivery system consisting of 34,200 kilometers of pipeline, serving 2.5 million Albertans in 291 communities across Alberta.

ATCO Gas will open two new operations centres in 2004 to better meet the needs of the high growth areas of Red Deer in central Alberta and Strathcona County near Edmonton.

Customer demand for accurate, timely energy consumption information in a deregulating marketplace has translated into several initiatives designed to provide customers with regular monthly meter readings.

In its first full year of operation some 16,600 meter moves were completed under The Meter Relocation and Replacement Program (MRRP) at a total cost of approximately $20.5 million. The program objective is to improve safety, efficiency and accessibility to meters while at the same time improving billing accuracy through the replacement of standard meters. It is anticipated that some 200,000 meters will be moved outside of customers' homes over the life of the program.

Increasing customer demand for control over their individual energy consumption and charges inspired the innovative installation of 201 separate gas meters off of a single service line at an Edmonton condominium complex. Unlike traditional condominium service in which total energy bills are divided equally amongst residents, the Edmonton project provides individual condominium owners usage readings of their specific gas consumption. The project has proven very popular with residents and is setting the standard for new condominium construction throughout Alberta.

During 2003, ATCO Gas completed the replacement of its existing dispatch system. This replacement will allow ATCO Gas customer servicemen to become more efficient, as well as allowing them to be in contact with the central dispatch function at all times.

ATCO Gas continues to provide Albertans with the lowest regulated delivery rates in Canada. In 2002, ATCO Gas submitted an application to the EUB for an increase in delivery rates for 2003 and 2004. The application reflected the increased investment needed to meet growth in Alberta's robust economy. The EUB approved an increase in delivery rates for 2003 and 2004.

CU WATER

Through its pipeline system, CU Water offers reliable delivery of safe, high-quality treated water to municipalities and businesses in east-central Alberta. CU Water also owns and operates the municipal water distribution system (including metering and billing) in one community and is pursuing acquisition of other systems.

In 2003, the company achieved significant industrial growth with extensions to its pipeline system in east-central Alberta to bring water to seven intensive livestock producers. CU Water continues to add industrial and residential services along its existing pipeline system.

Photo: ATCO Electric senior serviceman Kevin Laing takes time out of his day to talk with Alvin Meyer, a director of the Stirling Rural Electrification Association who lives near Heisler, Alberta.

ATCO ELECTRIC

ATCO Electric had a near record level construction year in 2003, adding 4,422 more customers to our 9,000 km of transmission line and 58,000 km of distribution line. Capital expenditures were $169.2 million. The company provides electricity service to 246 Alberta communities serving a population of 438,000.

To boost capacity and further improve the reliability of Alberta's electric grid, ATCO Electric started work in September 2003 on the $95 million, 350-kilometre Fort McMurray — Whitefish Lake transmission line. The 240 kilovolt (kV) transmission line will be the third major line between Fort McMurray and Edmonton, and will increase transport capacity from about 350 MW to 600 MW.

The project, expected to be completed in August 2004, also includes three substations and expands an existing substation to supply the growing needs of the area south of Fort McMurray. It will be the first line of its size and length to be constructed and completed in just one year's time.

Monthly meter reading is now automatic for most of ATCO Electric's 202,268 customers. With 160,000 automated meter reading (AMR) devices now installed, more than 90 per cent of our customers receive an actual meter read each month instead of an estimate.

In 2003, ATCO Electric introduced AMR and monthly billing for farm customers. Previously, farm customers were billed quarterly and their meters were read twice a year.

Monthly meter readings and billings give our customers timely accurate information about the cost of energy they use, and reduce the need for large bill adjustments. In addition, ATCO Electric can better anticipate the electricity needs of our customers, and can more accurately report customer consumption to the Alberta Electric System Operator and to the customer's retailer if they choose one.

Landmark Agreement

In the summer of 2003, ATCO Electric entered into an agreement with the Sturgeon Lake Cree Nation to explore opportunities to encourage Sturgeon Lake youngsters to stay in school and pursue careers with ATCO, to participate in career fairs and develop job shadowing opportunities. The agreement, the first of its kind signed by ATCO Electric and an Aboriginal community, is part of a company effort to develop the same close relationships with First Nations and Metis Settlements as the company has with all of the communities it serves.

J.R. (Dick) Frey

As part of the agreement, ATCO Electric will continue its ongoing efforts to involve Sturgeon Lake residents and companies in brushing and clearing work. The company will also consult with the First Nations about the location of planned line construction and avoid disturbing sensitive cultural sites.

Exceeding Environmental Standards

In May, ATCO Electric started a three-year project to remediate 75 operating and decommissioned isolated generation plant sites. Committed to minimizing our footprint on the environment, we are cleaning the sites to residential/parkland standards which are more stringent than requirements for commercial and industrial sites.

In 2003, contract crews worked at 22 sites. Fifteen of these sites were completed and seven will have remediation activities that carry over into 2004. Working closely with landowners, municipalities and other interested parties the work is being done as quickly and efficiently as possible with minimal impact. The remediation project is slated to be completed by fall 2005.

J.R. (Dick) Frey
Managing Director, Utilities

Logistics and Energy Services Group

Photo: ATCO Midstream owns and operates a number of sour gas plants in Alberta and Saskatchewan including the Golden Spike Gas Plant near Edmonton, Alberta.

The Logistics and Energy Services Group includes three companies, ATCO Frontec, ATCO Midstream and ATCO Pipelines, focused on providing advanced logistics and energy management services to a diverse customer base.

ATCO Frontec, ATCO Midstream and ATCO Pipelines are focused on providing advanced logistics and energy management services to a diverse customer base.

LOGISTICS & ENERGY SERVICES

- ATCO Frontec Corp.
  - ATCO Frontec Western Operations (division)
    - ATCO Frontec Security Services
    - ATCO Frontec Property Management
  - ATCO Frontec Services Ltd.
  - ATCO Frontec Services Inc. (USA)
  - ATCO Frontec Logistics Corp.
  - Nasittuq Corporation
  - Torngait Services Inc.
- ATCO Midstream Ltd.
- ATCO Gas and Pipelines Ltd.
  - ATCO Pipelines (division)

ATCO FRONTEC

ATCO Frontec undertook to redefine its business efforts in 2003. To improve its growth strategy the company closely reviewed its skills and the related opportunities in the marketplace. As a result, ATCO Frontec's core capabilities are defined in the areas of camp support services, facilities operations and maintenance and property management services. Today, the company is clearly focused and "well positioned" for the future.

In September, after three successful years, ATCO Frontec's contract to provide support services to Canadian Forces personnel deployed in Bosnia-Herzegovina came to term. The personal and professional achievements of the project were enormous for this first-ever awarded government outsourcing contract, designed to allow Canadian Forces personnel to focus on peacekeeping activities. In final performance ratings from the Canadian Government, ATCO Frontec earned its highest ever ratings for operation and maintenance activities and earned a near perfect score for the transition-out requirements.

Photo: Relocation of ATCO Pipelines Turner Valley #2 (273 mm/10 inch) pipeline located in southwest Calgary. The line relocation occurred in July and August of 2003 to accommodate new housing developments in the area.

ATCO Frontec retains its presence in the Balkans with a new project for the NATO Communications, Command and Control Organization (NC3A). The three-year contract, with two additional option years, to provide advanced information systems technological support to the NATO Stabilization Force Organization (SFOR), is based in Sarajevo. This project enhances the company's access to the NATO defence market.

On Canada's east coast, Torngait Services Inc. (TSI), a joint venture created in 1995 between ATCO Frontec and the Inuit of Labrador, played a significant role as activity levels at the Voisey's Bay nickel project in Newfoundland and Labrador heightened during the year. TSI participated in contract work relating to refurbishment and installation of the construction camp, general site services, air transportation, marshalling and port handling and communications infrastructure. TSI is also providing support to the ongoing exploration program at Voisey's Bay to collect core samples. Indirectly, through ownership in IKC-Borealis, a Newfoundland-based construction partnership, TSI participated in major and civil excavation work at the mine site.

As part of the company's new business focus, ATCO Frontec successfully won two separate facilities operations, maintenance and construction services contracts. The first is a five year contract with renewal options, for the Department of National Defence facilities located in London, Ontario and throughout southwestern Ontario. This award was followed by a three year contract, also with renewal options, for National Research Council facilities in the Ottawa area. ATCO Frontec manages more than 4.1 million square feet of property for customers in Alberta, Saskatchewan, Manitoba and Ontario.

The company's Northern Operations and Western Operations groups secured a variety of new contracts to augment and further diversify their existing business. Tli Cho Logistics Inc.,

Photo: A key objective in the 1995 establishment of Torngait Services Inc. (TSI), a joint venture between ATCO Frontec and the Labrador Inuit Development Corporation, was to participate in the Voisey's Bay project. For the past seven years, TSI has provided site support, camp operations, maintenance, logistics, procurement, project management and construction services to the project.

a jointly owned corporation of ATCO Frontec and the Dogrib Rae Band, continues to successfully provide a range of site and construction services, as well as fuel supply at the Diavik diamond mine in the Northwest Territories.

Both the Alaska Radar System, managed by ARCTEC Alaska, a joint venture between ATCO Frontec and Arctic Slope World Services Inc. (ASWS), and the Solid State Phased Array Radar System, managed by ARCTEC Services, another joint venture between ATCO Frontec and ASWS, continue to meet and exceed customer expectations.

ARCTEC Alaska is responsible for the complete operation and maintenance of 18 radar sites in remote areas throughout Alaska, ten of which are located above the Arctic Circle. ARCTEC Alaska also provides support to the project headquarters and support services to the Region Operations Control Center and the Maintenance Control and Communications Center at Elmendorf Air Force Base.

ARCTEC Services is under contract with the United States Air Force Space Command to operate and maintain five geographically separated and diverse radar sites in the United States, United Kingdom, and Greenland.

The past year represented ATCO Frontec's 15th anniversary managing the NORAD's North Warning System project. Today, through Nasittuq Corporation, the agent for a joint venture partnership between ATCO Frontec and Pan Arctic Inuit Logistics Corporation, the project consistently achieves and exceeds operational availability requirements for 46 radar sites located across Canada's north and five logistics support sites located in Inuvik, Cambridge Bay, Hall Beach, Iqaluit, and Goose Bay. Nasittuq earned a renewal contract for this project for up to 10 years in the spring of 2002.

Potential and Future Opportunities/Challenges

ATCO Frontec will continue to lead the efforts to position the ATCO Group of Companies for participation in northern opportunities as the gas pipeline projects unfold. Working on a focused basis with ATCO Structures, ATCO Midstream, ATCO Pipelines, ATCO Gas and ATCO Electric, specific opportunities with project proponents have been identified.

ATCO Frontec's success in developing and sustaining long term Aboriginal relationships, developing northern logistics and camp support services, and complementing Aboriginal training programs is viewed as adding significant value.

ATCO Frontec will focus on creating new opportunities in the segment of camp support services primarily in the mining industry, expand its presence in the Balkans with NATO, and pursue further opportunities with the Canadian Department of National Defence, the United States Department of Defence and the U.S. Air Force. ATCO Frontec will also focus on public sector outsourcing opportunities in the areas of facilities operations and maintenance and property management services where significant growth potential exists.

ATCO MIDSTREAM LTD.

ATCO Midstream provides services in gas gathering and processing, storage, natural gas liquids extraction and energy services to a broad customer base. The Company focuses on building long term relationships by providing customers with cost-effective, timely, integrated solutions. ATCO Midstream has ownership in 15 natural gas processing and compression facilities with a gross licensed processing capacity of 2,060 million cubic feet per day. The Company also owns and operates approximately 1,000 kilometres of raw natural gas pipeline. Established in 1992, the Company has proven to be a reliable partner in today's energy industry.

ATCO Midstream's Gas Gathering and Processing (GG&P) Group continued to maintain a high standard in 2003 by operating its gas plants with an availability of 97.5%. The GG&P Group was successful at increasing volumes at several plants despite reduced drilling activity in the first half of 2003. Compression projects at Carbondale and Villeneuve were completed in 2003 to increase throughput at each of these facilities.

Cost control, stronger natural gas liquids extraction margins, and increased facility throughput contributed to the Natural Gas Liquids (NGL) Group success in 2003. As a significant ethane producer within Alberta, ATCO Midstream was well positioned to take advantage of increased ethane prices and executed a long term ethane sales agreement. This agreement increased operating income and reduced commodity price exposure. Although significantly mitigated by the long term ethane agreement, commodity price exposure remains a major focus of the NGL Group who manages this risk on a daily basis. The NGL Group works closely with its partners and customers to ensure ATCO Midstream is ready to take advantage of opportunities to secure throughput at its facilities.

The Storage and Energy Services (S&ES) Group's success was achieved as a result of providing value-added services to its customers. In 2003, a significant amount of time was expended by Midstream to support regulatory proceedings. Market volatility will continue to be the largest influence on the Storage and Energy Services Group's results.

ATCO Midstream will continue to pursue growth opportunities in its core business areas but will also position itself for growth in new geographic areas such as the Far North, East and West coasts. In addition, the company will be expanding its expertise to pursue projects in the Heavy Oil and Natural Gas from Coal industries. While longer term in nature to develop, these emerging areas will offer Midstream significant long-life investment opportunities.

Health, Safety and Environment

In 2003, ATCO Midstream was successful in achieving a Certificate of Recognition for its safety program through an external audit certified by the Canadian Petroleum Safety Council (CPS). The CPS includes representatives from eight Canadian petroleum associations, ten government departments and six Workers' Compensation Boards.

The company also successfully completed an external audit of Environmental policy and procedures in accordance with CAPP guidelines. Maintaining strict environmental, health and safety standards continues to be a major priority.

ATCO PIPELINES

ATCO Pipelines provides natural gas transportation services to producers, major industrial users and gas distribution companies in Alberta.

ATCO Pipelines continued to connect new producer receipts and develop new industrial markets on its system in 2003. While overall volume throughput increased slightly, contracted demand declined marginally due to price competition at dually connected gas plants and declines in gas well deliverability within the company's service area.

In March, Calpine's Calgary Energy Centre, a new 250 MW power plant, which consumes up to 55 terajoules (TJ)/day of natural gas, commenced commercial operation. This important new market is served by ATCO Pipelines' South integrated system.

Photo: Located near the community of Tuktoyaktuk, N.W.T., "Bar 3" is one of 46 radar sites on NORAD's North Warning System which is operated and maintained by Nasittuq Corporation, the agent for the joint venture between ATCO Frontec and Pan Arctic Inuit Logistics Corporation. "Bar 3" also serves as a "hands-on" training site for those participating in the Inuit Training Program which was successfully launched in 1995 to provide the Inuit with the opportunity to learn new job skills. Trainees in the program accompany company personnel to site and learn first-hand how regular and preventative maintenance activities are completed.

In June, ATCO Pipelines completed construction of a 6.8 km long, 219 mm diameter pipeline to deliver an incremental 50 TJ/day of natural gas to the Dow Chemical complex at Fort Saskatchewan.

Drilling activity in the vicinity of the Grande Cache pipeline system was very active, and resulted in a producer commitment of 15 TJ/day of incremental natural gas receipts which will be brought on-stream in early 2004.

In the Edson area, ATCO Pipelines continued to connect incremental producer natural gas volumes. In September, ATCO Pipelines completed a system pressure upgrade project on its Jasper transmission system which provided for the transportation of an additional 12 TJ/day of gas.

Throughout 2003, ATCO Pipelines continued to increase natural gas receipts on its Grande Prairie system. ATCO Pipelines is currently reviewing an expansion of that system to accommodate more producer gas that is awaiting takeaway capacity.

As part of the company's on-going pipeline integrity program ATCO Pipelines, replaced a 1.2 km pipeline crossing of the Athabasca River near Fort Assiniboine to ensure service reliability to customers.

In April, ATCO Pipelines commenced delivery service to TransGas Limited, the Saskatchewan natural gas transmission company. Firm commitments of 15 TJ/day were signed with deliveries as high as 32 TJ/day in 2003.

Shippers continued to have the choice of delivering natural gas to the Alliance Pipeline at both Edson and Paddle River, with a peak day nomination of 200 TJ/day occurring in November.

ATCO Pipelines' network of natural gas transmission lines with connections to numerous pipeline systems, end use markets, and significant producer receipts has led to increased system liquidity for buyers and sellers of natural gas. In August 2003, the Natural Gas Exchange, a computer-based gas and power trading system, began listing the ATCO

Pipelines' North gas price. This will further increase system liquidity and provide price availability for all of ATCO Pipelines' customers.

Regulatory

The 2002 expiry of settlements with most customer groups required a 2003/04 Phase I General Rate Application (GRA) for ATCO Pipelines (North and South). The EUB Decision was issued in December which established the 2003 revenue requirements using a 9.5% return on equity and 43.5% equity. A Phase II GRA was subsequently filed which will result in new, cost based tolling for the various customer groups. The proposed new rates, designed to reflect the multiple markets the company currently serves, will position ATCO Pipelines to compete for new supplies and end-use natural gas markets in 2004 and beyond.

The EUB has recognized that the competitive issues between ATCO Pipelines and the much larger NOVA Gas Transmission Limited (NGTL) require resolution and has directed NGTL to file 2004 Phase I and Phase II GRA's; hearings will be held in early 2004, the same time frame as ATCO Pipelines' 2004 Phase II proceeding. This will provide the opportunity to address competitive issues so that a level playing field exists in the future.

ATCO Pipelines is participating with ATCO Gas and ATCO Electric in the Generic Cost of Capital proceeding currently before the EUB. The Decision will establish ATCO Pipelines' return on equity and capital structure for 2004 and future years.

The EUB issued a decision pertaining to ATCO Pipelines' North system methodology for allocation of Unaccounted-For-Gas (UFG). The decision resulted in a reduced UFG allocation to ATCO Pipelines' transportation customers.

ATCO Pipelines implemented the new ATCO Group Inter-Affiliate Code of Conduct as ordered by the EUB. The Code governs transactions and services between ATCO companies. The company was in full compliance with all Code provisions by year end.

Current Business Environment and Future Opportunities

ATCO Pipelines operates a pipeline system of 8,310 kilometres connecting producer receipts with intra-Alberta end-use markets and providing interconnections with the Nova Gas Transmission, Alliance Pipelines and Many Islands Pipelines systems that move gas out of Alberta. With this significant infrastructure footprint, ATCO Pipelines is well positioned to provide shippers access to markets of their choice.

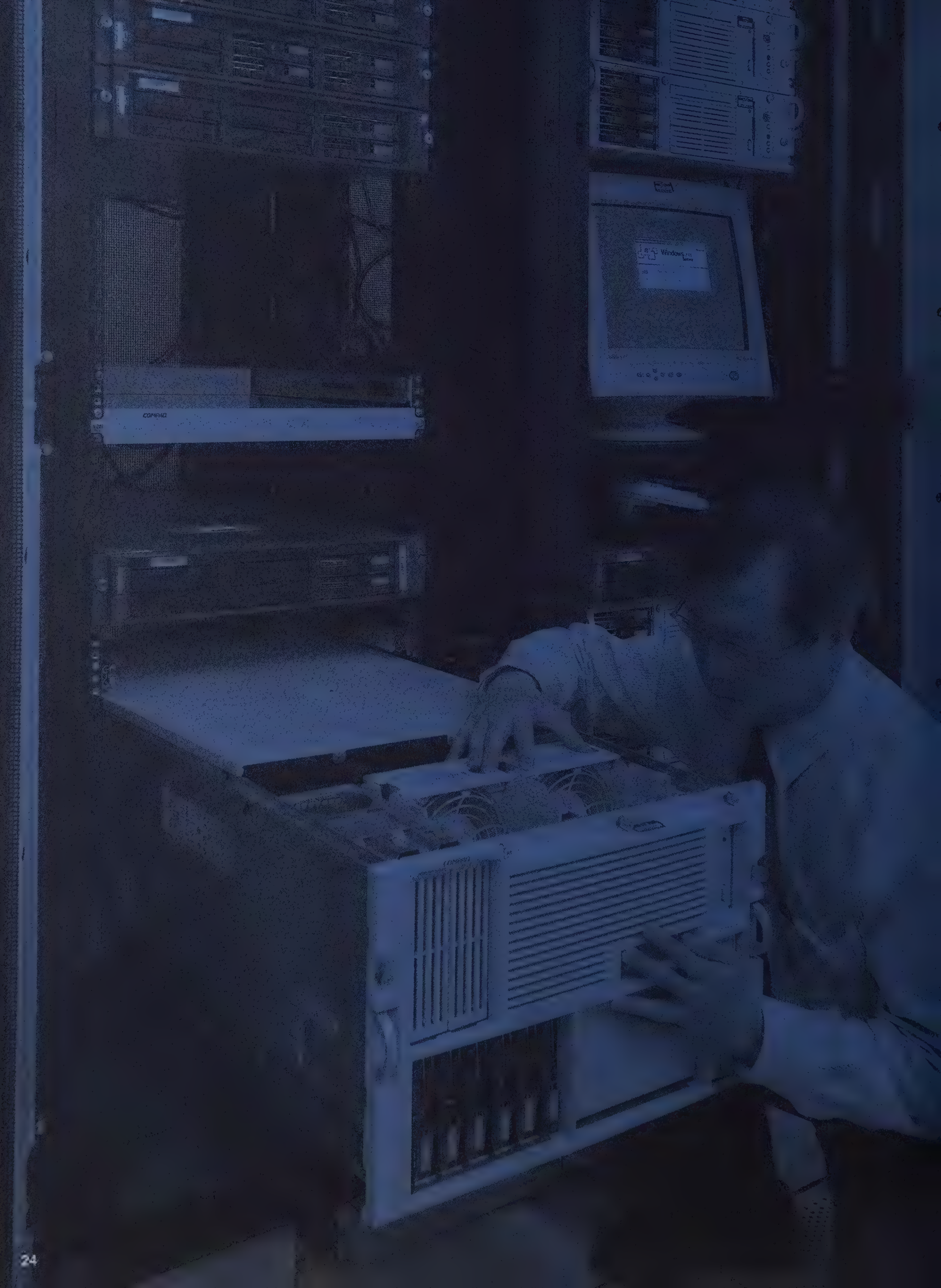
Michael M. Shaw

Forecast industrial growth in the Fort McMurray, Edmonton and Fort Saskatchewan regions, largely as a result of Oil Sands developments and associated refining requirements, will contribute to growth in throughput on ATCO Pipelines' system.

A developing natural gas supply called Coalbed Methane is emerging as a future growth opportunity in Alberta. The primary target areas for exploitation of this new and expanding energy source are within ATCO Pipelines' service territory.

Michael M. Shaw

Michael M. Shaw
Managing Director, Logistics & Energy Services



Technologies Group

Photo: ATCO I-Tek employee Terry Gee installs a new hardware component in one of more than 100 Intel and Unix servers located throughout ATCO I-Tek's client sites.

In 2003, ATCO I-Tek, ATCO Travel, Genics and ASHCOR Technologies continued to expand their markets and build solid reputations as providers of high quality, innovative products and client-focused services.

ATCO I-Tek's 2003 performance positioned the company for future growth as a full service provider in customer care and billing, information technology and applications, offering complex and diverse services to its expanding clientele.

TECHNOLOGIES

- ATCO I-Tek Inc.
  - ATCO I-Tek Business Services Ltd.
- ASHCOR Technologies Ltd.
- ATCO Travel Ltd.
- Genics Inc.

ATCO I-TEK

ATCO I-Tek delivers excellence in information technology, customer care and billing services to a diverse client group in Canada, providing competitive services in three key areas:

- Complete billing, call centre and customer care services
- Complete technology infrastructure lifecycle management including desktop, server, network, voice and call centre technologies; and
- Business applications development, integration, maintenance and enhancement services.

ATCO I-Tek worked effectively to prepare for the implementation of retail customer care and billing services for Direct Energy, North America's largest energy retailer. In preparation for the transition of retail services to Direct Energy, the company also worked to set up new distribution only services with ATCO's natural gas and electricity delivery companies, ATCO Gas and ATCO Electric.

Call Centre and Billing delivered more than 12.4 million utility bills, handled 2.1 million customer calls, processed more than $33 million in customer rebates, produced more than 45,000 refund cheques and collected more than $2 billion in revenue on behalf of clients. The Call Centre consistently met high standards of customer care, providing fast and friendly call centre service. These standards were met with call volumes and credit activity significantly above 2002 levels, primarily as a result of higher energy prices. Billing delivered accurate and timely utility energy bills to more than one million customers, outperforming its competitors in a year of escalated customer concern regarding higher energy prices.

Photo: ATCO I-Tek employees Leslie Yeoman and Tahir Filipovic collaborate to ensure a seamless transition of over 4,000 ATCO Group computers to the Microsoft Windows XP operating system.

Applications provided support for over 200 business software applications to the ATCO Group of companies. In 2003, this division worked closely with Direct Energy in preparing the customer care and billing system to be ready for the implementation of retail services. Applications also supported ATCO Gas and ATCO Electric in the preparation of the transition of ATCO's natural gas and electricity regulated retail business to Direct Energy, the alignment of the natural gas deregulation model with the electricity model, the implementation of the terms and conditions as distribution only companies and the evolving deregulation rule changes required by the provincial government. The division also successfully implemented the Oracle Financial Information System for the ATCO Group Corporate Office, ATCO Frontec and ATCO Midstream in 2003. ATCO I-Tek will continue to implement Oracle Financials throughout the ATCO Group of companies to create a consistent financial reporting system.

Technologies provided technology infrastructure planning, implementation and 24/7 technical support for more than 4,000 workstations, operated a network connecting more than 130 locations throughout Canada, including the Canadian North and the United States, plus handled more than 78,000 service requests. In 2003, this division successfully migrated ATCO's server and desktop environments to current Microsoft technologies, protected ATCO's environment from security breaches and viruses, supported all applications initiatives, implemented new Call Centre technologies and met all client service level requirements.

Photo: ATCO I-Tek call centre employee Preetika Prasad is one of more than 210 call centre representatives that answered 2.1 million customer inquiries on utility billing and service issues.

The major achievements of 2003 were the progress made on retail and distribution call centre, billing and customer care services implementation with key clients Direct Energy, ATCO Gas and ATCO Electric plus the progress made in support of ATCO Gas and ATCO Electric in the changing energy environment. Commencement of the Direct Energy contract remains conditional upon closing of the sale of the ATCO Gas and ATCO Electric retail energy businesses to Direct Energy.

Overall, ATCO I-Tek's 2003 performance positioned the company for future growth as a full service provider in customer care and billing, information technology and applications offering complex and diverse services to its expanding clientele.

ATCO TRAVEL

ATCO Travel is a leader in travel management solutions serving corporate clients and the general traveling public. In 2003, ATCO Travel continued to demonstrate solid performance despite the downturn in corporate travel, the war in Iraq, the Severe Acute Respiratory Syndrome (SARS) outbreak, and other natural disasters. The company also celebrated its 25th Anniversary in September, a significant milestone in a very competitive marketplace.

2003 saw growth in the new corporate accounts division including ATCO Travel being awarded the consolidated corporate travel management programs for Alberta Treasury Branch Financial, the University of Calgary, and the Calgary Exhibition & Stampede. ATCO Travel also expanded its locations by acquiring a travel office branch in the Town of Canmore.

As uncertainty continues in the travel industry, ATCO Travel will maintain focus on the value-added service component of delivering electronic solutions to reduce complexity in pricing options for customers as well as reducing overhead and maximizing its ability to procure supplier commodities with its purchasing expertise.

ATCO Travel is well positioned for growth in 2004 with its four key service models: Corporate Travel Solutions, ATCO Vacations Services, Groups and Meeting Planning and Airline Charter Programs.

GENICS

Genics, a 24-year old company within the ATCO Group, is an innovation company specializing in the development and manufacture of environmentally friendly, worker safe products used to preserve wood and extend the in-service life of wood assets for North American utility, commercial and residential markets. The Genics Cobra™ line sets new standards for effectiveness of treatment, ease of application, worker safety and environmental friendliness. Genics Cobra™ products offer an excellent alternative to traditional methods of wood preservation, repair and maintenance. Easier to install, comparably priced, longer lasting and safer to use, the Genics line of Cobra™ products is the best line of defense against the forces that destroy wood.

Although sales were lower than expected due to continued pressure on utilities to reduce maintenance spending in 2003, Genics continued to strengthen its position in both the Canadian and American marketplace. In Canada, Genics added Aquila and Toronto Hydro and Energy to its customer list. The U.S. market extended into Texas, Oregon, Louisiana, Tennessee, Illinois, Maryland and Pennsylvania, with new U.S. utility and contractor customers signing on.

In 2003, rigorous testing began on an exciting new Genics product. CobraCrush MDT (Mould Decay Termites) is made up of the same environmentally friendly wood preservation products as CobraRod, but is crushed into micron sized powder. When manufacturing oriented strand board (OSB), CobraCrush MDT is mixed with strands and resin to ensure protection from mould, decay and termites. In the first quarter of 2003, joint lab tests on OSB treated with CobraCrush MDT were completed with several OSB manufacturers. Following these successful lab tests, the research and development (R&D) CobraCrush melter was commissioned. Genics performed trials and undertook an extensive R&D plan to prove out properties of CobraCrush MDT in treated OSB panel in the third quarter. Genics received U.S. Environmental Protection Agency (EPA) and Health Canada's Pest Management Regulatory Agency (PMRA) approval for CobraCrush and continues rigorous R&D programs with several OSB producers.

In 2004, the company will continue to focus on growth and market share for the U.S. utility market, and on new opportunities in CobraCrush MDT treated OSB.

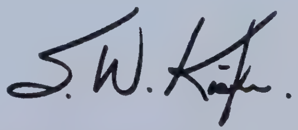
Siegfried W. Kiefer

ASHCOR

ASHCOR Technologies markets coal combustion products from ATCO Power's coal-fired generating stations in Alberta. The predominant product marketed is fly ash, the non-combustible residue remaining after coal is consumed in a power plant furnace. It is designated a supplementary cementing material by the Canadian Standards Association. Its primary use is as a partial replacement for cement powder in concrete products and in oil well cements. Replacement of Portland Cement by fly ash, a by-product, reduces Green House Gas (GHG) emissions.

During 2003 ASHCOR continued to demonstrate steady growth in year-over-year sales volumes. Since its inception in 1998, ASHCOR has established itself as a premier supplier to the construction and oilwell drilling markets in western Canada.

ASHCOR continues to pursue research and development of value-added products derived from coal combustion products.



Siegfried W. Kiefer
Managing Director, Technologies

Power Generation

Photo: One of two heat recovery steam generators nearing completion at the 580 MW Brighton Beach combined cycle power plant in Windsor, Ontario. The plant will be the largest gas-fired combined cycle plant in Canada.

The Power Generation Group combines the independent power plants built and operated by ATCO Power with the regulated legacy plants in Alberta previously owned and operated by ATCO Electric. The Group has operations in Canada, the United Kingdom, and Australia and is an acknowledged leader in developing, constructing and operating environmentally progressive natural gas fired plants.

Photo: ATCO Power commissioned its first hydroelectric project, the 32 MW Oldman River project, in July of 2003.

Photo: The 260 MW Cory cogeneration plant, a joint venture with SaskPower International located near Saskatoon, supplies steam to the PCS Cory Potash Mine and electricity to the Saskatchewan grid.

The Power Generation Group operates a number of proven-technology, state-of-the-art, efficient gas-fired cogeneration and peaking plants.

POWER GENERATION

- Alberta Power (2000) Ltd.
- ATCO Power Ltd.
  - ATCO Power Canada Ltd.
    - ATCO Power Alberta Ltd.
  - ATCO Power Australia Pty Ltd.
  - ATCO Power Generation Ltd. (UK)
    - Thames Valley Power Limited
    - Thames Power Limited
      - Barking Power Limited
      - Thames Power Services Limited

2003 was another significant year for the growth of the Power Generation Group. The Group realised strong overall plant performance; achieved commercial operations on four new plants totalling 632 megawatts (MW) of capacity in Alberta and Saskatchewan and progressed construction on its 580 MW generation plant in Ontario.

ATCO Power is well positioned to maintain its rank as a leading Canadian-based independent power producer. At the end of 2003, the Group operated a portfolio of 19 plants with a combined capacity of 4,400 MW, and had a total ownership interest of 2,561 MW in these plants. The Group has a wide portfolio of efficient generating assets, with the vast majority of electric and steam output sold under long-term contracts and financed with fully amortizing long-term non-recourse loans.

Canada

The 580 MW natural gas-fired combined-cycle Brighton Beach generating plant in Windsor, Ontario is currently nearing the final stages of construction leading to commissioning. This is ATCO Power's first project in Ontario and demonstrates its successful entry into deregulated power markets following those of the United Kingdom, South Australia and Alberta. ATCO Power and its partner, Ontario Power Generation Inc., will sell all of the output from this plant under a long-term energy conversion agreement signed in November 2001 with Coral Energy, which will deliver all the natural gas fuel. Construction began in the second quarter of 2002, with completion planned for summer of 2004. The partnership achieved financial close on a $403 million long-term, non-recourse debt financing for the Brighton Beach Project in 2002.

During the year, four new projects achieved commercial operations. The 260 MW Cory cogeneration plant at the Potash Corporation of Saskatchewan mine near Saskatoon achieved commercial operations on January 15, 2003. This plant is selling all the electric energy produced to Saskatchewan Power Corporation and steam to Potash Corporation of Saskatchewan under long-term agreements. The plant was officially opened on May 28, 2003 at a ceremony attended by community, government and corporate leaders.

The 170 MW Muskeg River cogeneration plant near Fort McMurray achieved commercial operations on January 1, 2003, and is 70% owned by the ATCO Power Generation Group and 30% owned by SaskPower International Inc. This plant is selling approximately half the electric energy and all the steam to the Muskeg River mine site under a long-term agreement and the balance of the electric energy is being sold to the Alberta Electric Systems Operator (AESO).

The Power Generation Group is sole owner of the 170 MW Scotford Upgrader cogeneration plant, which achieved commercial operations on December 1, 2003. This plant is selling approximately 80% of its electric energy and all the steam to the Scotford Upgrader under a long-term offtake agreement with the balance of the electric energy sold to the AESO.

Completion of the 32 MW Oldman River hydroelectric plant near Pincher Creek, Alberta took place in July 2003. The Oldman River Dam Project is the Group's first independent hydroelectric project. This run-of-river hydro project will provide a new source of clean generation to southern Alberta, where additional capacity is required. The plant was officially opened on September 30, 2003 at a ceremony

↑ *Photo: The 580 MW Brighton Beach Power Plant, a partnership between ATCO Power and Ontario Power Generation, will be in commercial operation in early summer 2004.*

↓ *Photo: ATCO Power, in partnership with SaskPower International, is developing a 150 MW wind farm in southern Saskatchewan to produce renewable energy starting in 2005.*

attended by Alberta Premier Ralph Klein and the Chief and members of the Piikani Nation, which has an option to purchase a 25% interest in the plant.

On January 1, 2001, the sale of output from the regulated legacy plants commenced under long-term Power Purchase Arrangements. The main legacy plants are the coal-fired stations at Sheerness and Battle River, whose ownership is held by Alberta Power (2000) Ltd. Sheerness is a 750 MW plant operated by ATCO Power and jointly owned with TransAlta Utilities. The 679 MW Battle River plant is solely owned by Alberta Power (2000). Both of these plants achieved high availability operations for the year despite severe drought conditions, which caused the Battle River cooling water reservoir, a 12-metre dam located on the Battle River, to fall to record low levels.

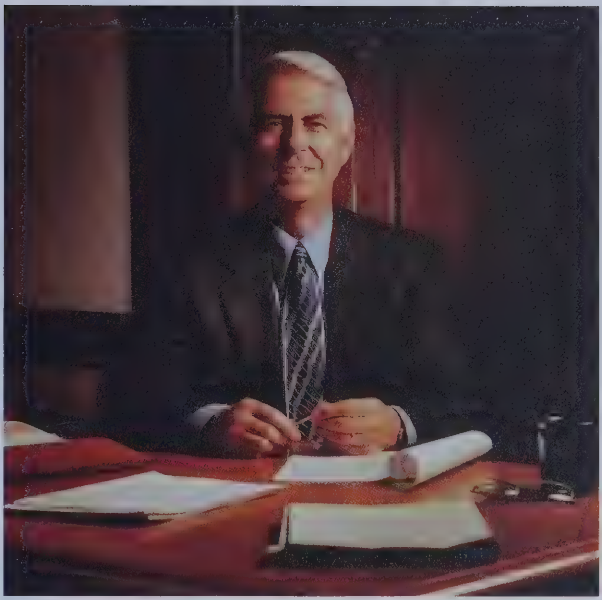
Another legacy plant, the 150 MW coal-fired H.R. Milner plant near Grande Cache, was sold to the Alberta Balancing Pool in early 2001, but was operated by ATCO Power under an agreement extending to March 31, 2004. The Balancing Pool completed the sale of the plant to a third party on January 29th, 2004, which terminated ATCO Power's operating arrangement.

The Group operates a number of proven-technology, state-of-the-art, efficient gas-fired cogeneration and peaking plants. In British Columbia, the 120 MW McMahon cogeneration plant sells all its electric energy output under a long-term agreement with BC Hydro and steam output to the Duke Energy gas plant. In Alberta, the Group's portfolio of plants includes the 480 MW Joffre cogeneration plant, the 85 MW Primrose steam enhancement plant, the 89 MW Rainbow Lake cogeneration and peaking plants, and the 43 MW Poplar Hill and 46 MW Valleyview peaking plants.

In September 2003 the Government of Saskatchewan announced that ATCO Power had been chosen to develop jointly with SaskPower International Inc. 150 MW of wind generation in Saskatchewan. Work is progressing on the equipment selection, site selection, and offtake contract.

United Kingdom

ATCO Power's principal United Kingdom asset is the 1,000 MW gas-fired combined-cycle plant at Barking in east London. The company is the operator of the plant and has a 25.5 % equity interest. In November 2002, TXU Europe, one of the shareholders/offtakers of Barking Power Limited petitioned the High Court for the appointment of an Administrator. In 2003 Barking Power Limited filed a claim for compensation with the Administrator and was able to sell, under short-term bilateral agreements, the 275 MW formerly under long-term contract with TXU Europe.

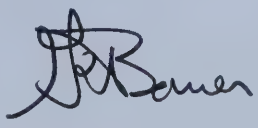


Gary K. Bauer

ATCO Power is a joint owner with EDF Energy plc, formerly London Electricity, of a 14 MW cogeneration plant at Heathrow airport in London.

Australia

ATCO Power's 180 MW Osborne cogeneration plant near Adelaide was commissioned in 1998. The Bulwer Island cogeneration plant commenced commercial operation on January 1, 2001. The 33 MW Bulwer Island plant supplies electricity and steam to British Petroleum's Bulwer Island Refinery in Queensland. Both plants are jointly owned with Origin Energy.



Gary K. Bauer
Managing Director, Power Generation
(retired February 2, 2004)

Electric Power System

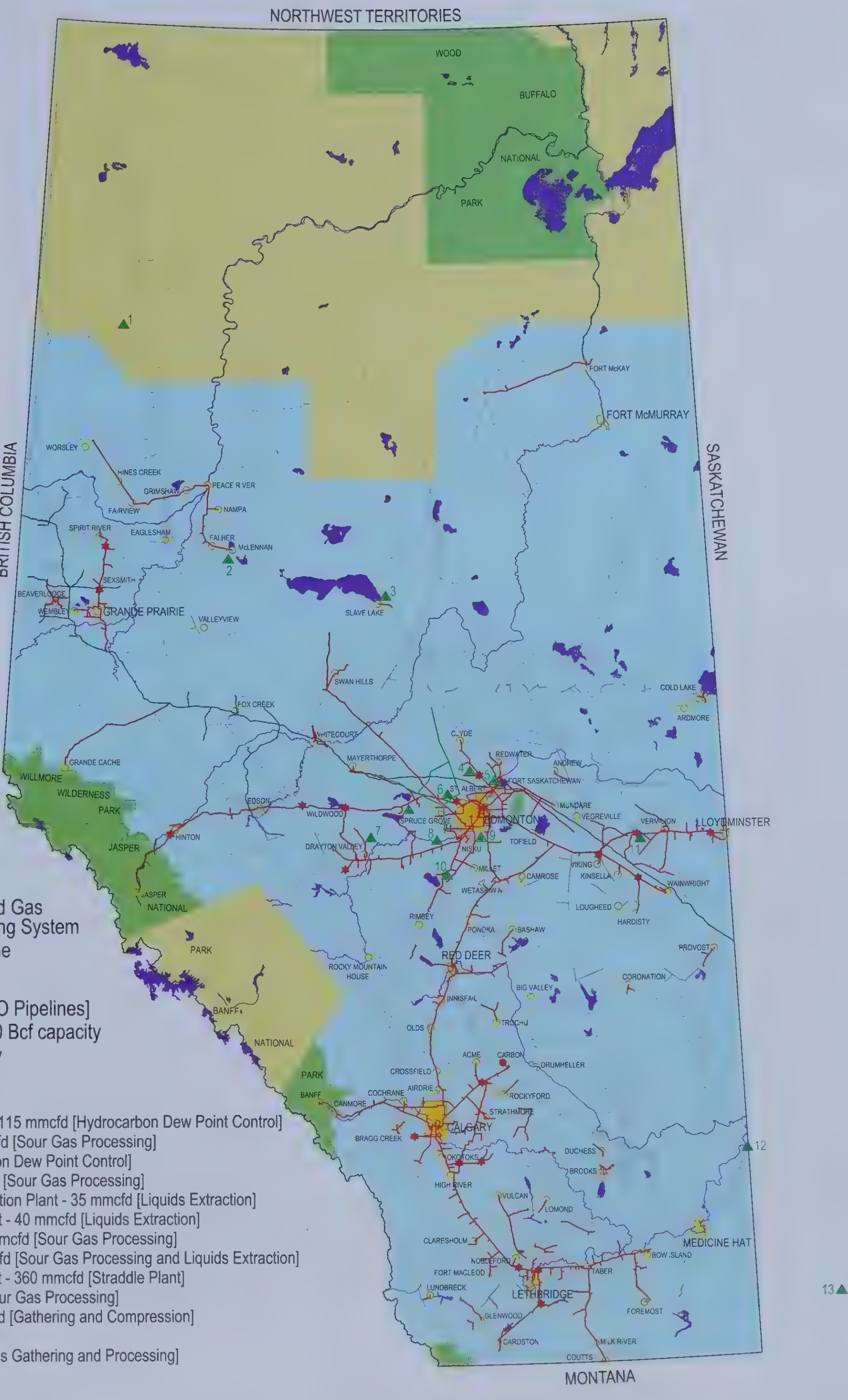
- ATCO Electric Generating Stations
- ATCO Power Generating Stations Connected to Alberta Interconnected System (AIS)
- ATCO Power Hydroelectric Projects
- ATCO Electric 240, 144, 72kV Transmission Lines
- Other 500, 240, 144, 72kV Transmission Lines

- ATCO Electric Service Area
- ATCO Electric Division Office
- ATCO Electric Service Point

ATCO POWER PLANTS

Rainbow Lake
Muskeg River
McMahon
Primrose
Poplar Hill
Valleyview
Scotford
Joffre
Battle River
Sheerness
Oldman River
Cory (Saskatchewan)
H.R. Milner
(ATCO Power ceased operating Jan 2004)

Natural Gas System



□ ATCO Gas Service Area

— ATCO Pipelines

— ATCO Midstream Integrated Gas System - Raw Gas Gathering System

— Alliance Partnership Pipeline

— Other Gas Pipelines

★ Compressor Stations [ATCO Pipelines]

● Carbon Storage Facility - 40 Bcf capacity

★ Salt Cavern Storage Facility

▲ ATCO Midstream Facilities

1 Cranberry Processing Complex - 115 mmcfd [Hydrocarbon Dew Point Control]
2 Puskwaskau Gas Plant - 17 mmcfd [Sour Gas Processing]
3 Widewater - 7 mmcfd [Hydrocarbon Dew Point Control]
4 Carbondale Gas Plant - 55 mmcfd [Sour Gas Processing]
5 Fort Saskatchewan Ethane Extraction Plant - 35 mmcfd [Liquids Extraction]
6 Villeneuve Ethane Extraction Plant - 40 mmcfd [Liquids Extraction]
7 West Pembina Gas Plant - 147 mmcfd [Sour Gas Processing]
8 Golden Spike Gas Plant - 40 mmcfd [Sour Gas Processing and Liquids Extraction]
9 Edmonton Ethane Extraction Plant - 360 mmcfd [Straddle Plant]
10 Watelet Gas Plant - 21 mmcfd [Sour Gas Processing]
11 Kinsella Gas Gathering - 20 mmcfd [Gathering and Compression]
12 Empress - 1.1 Bcf [Straddle Plant]
13 Wolstitmor - 3 mmcfd [Solution Gas Gathering and Processing]

Environment Report

Canadian Utilities Limited participated in a variety of activities and environmental protection achievements in 2003.

Canadian Utilities continues to support Alberta Ecotrust, a unique organization that facilitates funding from the corporate sector to environmental groups undertaking progressive, community-based projects across the province. CU is an Alberta Ecotrust founding organization.

Canadian Utilities actively planted trees in communities through Tree Canada Foundation, a working partnership that has Canadians plant and care for trees in our urban and rural environments in an effort to help reduce the harmful effects of carbon dioxide emissions.

ATCO Gas invested $1.2 million to develop new research focused on determining viable commercial applications for power generated by Canada's first high voltage, fully operational fuel cell. In partnership with federal and provincial government agencies and the Northern Alberta Institute of Technology (NAIT), the $3.25 million project explores the potential of fuel cell production of environmentally friendly heat and power. Fuel cells, which work like a battery that does not need recharging, produce energy by combining hydrogen and oxygen. The most economical way to produce hydrogen is by using natural gas.

Photo: An ATCO EnergySense home evaluation helps customers increase their energy efficiency while safeguarding their indoor air quality. The home evaluations are provided as an EnerGuide for Houses service which ATCO EnergySense offers in cooperation with Natural Resources Canada.

ATCO Gas completed its eighth annual report to the Voluntary Challenge and Registry (VCR) Inc., reporting on the company's greenhouse gas emissions management program. ATCO Gas earned **"Gold Champion"** recognition for its participation in the federally sponsored VCR program, which encourages energy efficiency and conservation measures to reduce greenhouse gas emissions.

ATCO Electric started a three-year project to remediate 75 operating and decommissioned generation plants, cleaning the plants to residential/parkland standards which are more stringent than requirements for commercial and industrial sites. The remediation project is slated to be completed by fall 2005.

In partnership with Natural Resources Canada, **ATCO EnergySense** had great success with their **"Energuide for Homes"** program, performing nearly 8,000 home energy efficiency inspections throughout Alberta.

ATCO I-Tek marked its third year of participation in the Alberta Computers for Schools program, donating more than 900 recycled and refurbished computers, 1,065 computer monitors and 80 printers to Alberta schools and libraries.

Genics continues to provide innovative development and manufacturing of environmentally friendly, worker safe products used to preserve wood and extend the in-service life of wood assets. Genics products are designed for easy installation with minimum exposure to active chemicals, keeping the health and safety of workers, and protection of the environment as top priorities.

ASHCOR Technologies specializes in reducing, reusing and recycling coal-combustion byproducts produced by ATCO Power's generating stations. The primary byproduct, known as flyash, is marketed to the ready mix concrete and oil well cementing sectors.

ATCO Pipelines achieved **"Gold Champion"** recognition for the third consecutive year, in the 2003 Voluntary Challenge and Registry program to reduce greenhouse gas emissions. ATCO Pipelines continues to support and be involved in environmental committees and initiatives through industry associations.

Since 1990, **ATCO Pipelines** increased demand for natural gas as a clean burning energy fuel has increased ATCO Pipelines' annual throughput by nearly 50%. Despite this significant increase, the average emissions per regulation and meter station have been reduced. In 2002, average emissions per station were nearly 12% lower than 1990 levels. Specific details can be found in ATCO Pipelines 2003 Voluntary Climate Change Action Plan Update.

ATCO Frontec's principal areas of operation includes northern partnerships on projects such as the environmental reclamation of mine sites, including managing contaminated water and ensuring no further contamination occurs from wildlife access.

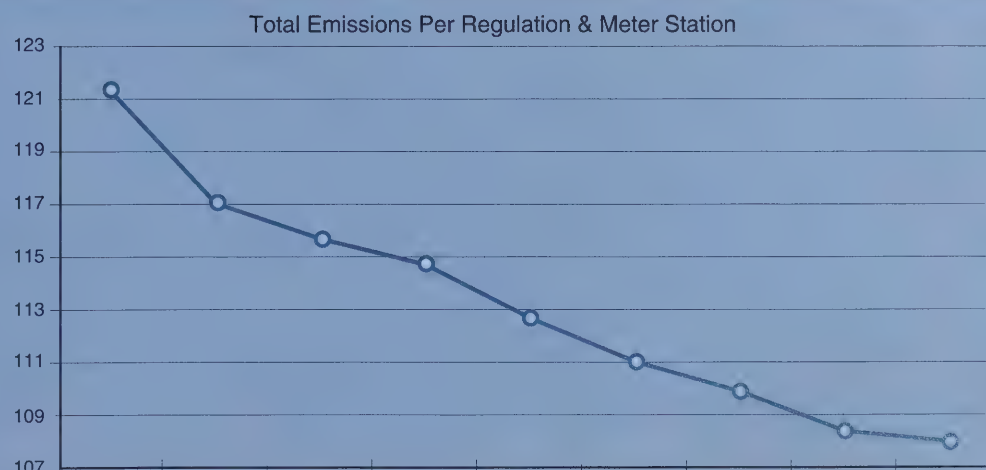
ATCO Power officially opened its emission-free, 32 megawatt Oldman River hydroelectric generating facility in September 2003. Capable of generating green-power for approximately 25,000 homes, the Oldman River project is ATCO Power's first-ever hydroelectric project and its first electricity generating facility in southern Alberta.

ATCO Power participated in the CASA (Clean Air Strategic Alliance) Electricity Project Team in 2003. This project looked at air emissions from power plants and developed an air emissions management framework, including performance specifications and standards, for existing and future power projects that will provide guidance for future regulations in Alberta.

ATCO Power participated in the Canadian Electricity Association's Mercury Monitoring Program. The program began in October 2002 and the first phase was completed in June 2003. Additionally, in October 2003 ATCO Power began investigating a pilot test program for the removal of mercury from stack air emissions.

ATCO Power has been chosen to work jointly with SaskPower International to develop 150 megawatts of wind generation in Saskatchewan by 2007. Approximately 50 to 150 turbines would be required to produce this amount of electricity, which is roughly the same amount used annually by 64,000 homes.

ATCO Pipelines Emissions Reductions Chart



1990	1995	1996	1997	1998	1999	2000	2001	2002
121.324	**117.098**	**115.760**	**114.794**	**112.777**	**111.146**	**110.018**	**108.531**	**108.143**

In 2002, ATCO Pipelines' average emissions per regulation and meter station were almost 12% lower than 1990 levels, despite having increased annual throughput by nearly 50%.

Your Community, Our Commitment

Committed to building stronger communities where our employees live and work, Canadian Utilities' tradition of community investment and support stretches back nearly a century.

Bringing Albertans together as neighbours is important to Canadian Utilities (CU). CU invested more than $3 million in donations to schools and hospitals throughout Alberta as well as providing support to hundreds of community based events.

- **Alberta Beef Producers Help Bank Campaign**
  CU co-sponsored a $100,000 innovative program to buy beef from Alberta producers and donate it to a network of 80 food banks throughout the province.

- **Hotel Selkirk, Fort Edmonton Park**
  CU participated in the replication of this historic Edmonton landmark to restore it to its original state of 1920's grandeur in the Fort Edmonton Park.

- **Calgary Winter Festival**
  More than 42 communities participated in the ATCO Gas Calgary Winterfest Community Events program.

- **Calgary Flames Adopt a Team**
  ATCO Gas is a founding partner of this successful Calgary Flames partnership which benefits more than 11,000 minor hockey players.

- **Royal Manitoba Winter Fair**
  One of Canada's largest agricultural events, CU is a founding sponsor of this week-long spring event.

Helping to build a healthy future for all Albertans is a key philosophy CU has developed.

- **Alberta Children's Hospital**
  By providing funds for the new Alberta Children's Hospital, CU is helping to build a world-class pediatric health care facility.

- **The Alberta Shock Trauma Air Rescue Society (STARS)**
  For almost 15 years, ATCO group and its employees contributed more than $340,000 to keep STARS helicopters in the air.

- **Colonel Belcher Seniors Care Centre**
  ATCO Gas provided the care centre's gas barbecues, courtyard heaters and natural gas lines.

- **United Way**
  Many CU companies participated in successful 2003 United Way campaigns again. ATCO Midstream received the United Way's 'Award of Excellence' which honoured their over 75% continual employee pledge participation.

- **ATCO Gas Employee Community Service Fund (ESCF) and Volunteer Recognition Fund**

  ATCO Gas invested a total of $1.5 million in community sponsorships and donations, including $215,000 contributed through the ATCO Gas (ECSF) and $15,300 in the company's Volunteer Recognition Fund.

- **ATCO Electric Employees for Community Health and Welfare Organizations (ECHO) and Volunteer Recognition Program**

  ATCO Electric invested a total of $615,145 in community sponsorships and donations including $62,704 contributed by the employees through ECHO which was matched by the company. Employees volunteered more than 17,200 hours in their communities.

ATCO Group has developed long-standing relationships with some of Canada's finest educational institutions.

- **ATCO Tyrrell Learning Centre**
  The ATCO Tyrrell Learning Centre opened in August, with ATCO Group donating $1 million for educational facilities at the Royal Tyrrell Museum in Drumheller.

- **Careers: The Next Generation**
  ATCO Electric participated in this industry-driven private/public partnership — dedicated to the career development of Alberta's youth.

CU strives to share with artists the attributes of excellence, passion and integrity that hard work and determination foster.

- **Youth Singers of Calgary**
  ATCO Group is a long-standing patron of this arts training program that has shaped the lives of thousands of people.

Photo: ATCO has been a solid supporter of STARS for almost 15 years contributing more than $340,000 to keep STARS in the air. Because of this contribution, the ATCO Group has been named to the Chairman's Circle of Giving. Nancy Southern, President & CEO, ATCO Group and Dr. Greg Powell, CEO, STARS unveil the ATCO Group logo on the STARS helicopter.

- **Cantos Music Foundation**
  Cantos provides music opportunities to the community through its collection of historic keyboard instruments, related electronic artifacts and programming such as Silent Movie Mondays, Organ à la Carte and a variety of school programs, such as Music Matters.

- **Vertigo Mystery Theatre**
  ATCO Group sponsored hearing impairment equipment required in the new location of Canada's only professional mystery theatre.

- **Northern Alberta International Children's Festival & Calgary International Children's Festival**
  These family oriented festivals present theatre, music, dance, storytelling & puppetry for children.

CU supports programs where leadership skills are developed and activities positively impact communities.

- **ITU Triathlon World Cup**
  Since 2001 CU has partnered annually with organizers to promote a world-class event with financial support, volunteers, community event PT Cruiser vehicle, loaner barbeques, inflatable tents and canopies.

- **Alberta Senior Games**
  CU has been a sponsor of the bi-annual Alberta Senior Games program since 1990.

CU works in many ways to build mutually beneficial relationships with Aboriginal communities.

In northern/Aboriginal communities such as Inuvik, Yellowknife, Resolute, Cambridge Bay, Hall Beach, Iqaluit and Goose Bay, CU has established extensive training and hiring programs.

- **Norquest College**
  CU contributes to programs that assist Aboriginal students achieve work place success.

- **Aboriginal Energy & Resource Development**
  CU participated in this high profile event that brought together the resource development industry and Aboriginal peoples.

Consolidated Five Year Financial Summary

(millions of Canadian dollars, except as indicated)		2003	2002	2001	2000	1999
EARNINGS						
Revenues		**3,742.6**	2,975.9	3,513.6	2,924.5	2,209.4
Operating expenses		**2,868.7**	2,170.5	2,696.3	2,088.7	1,427.4
Depreciation and amortization		**268.9**	244.4	241.9	238.9	229.6
Interest		**190.3**	184.1	198.7	196.2	182.2
Dividends on preferred shares		**–**	–	–	0.6	6.6
Interest and other income		**(33.4)**	(136.2)	(41.4)	(23.5)	(23.5)
Income taxes		**155.7**	189.9	164.0	179.4	172.1
Dividends on equity preferred shares		**33.1**	18.2	17.0	16.8	14.9
Earnings attributable to Class A and Class B shares		**259.3**	305.0	237.1	227.4	200.1
SEGMENTED EARNINGS						
Utilities		**97.7**	147.7	73.9	77.2	92.4
Power generation		**92.7**	75.3	94.7	96.5	67.2
Logistics and energy services		**60.8**	64.4	51.5	46.8	40.7
Technologies and other businesses		**19.1**	11.1	8.9	6.3	3.4
Corporate/eliminations		**(11.0)**	6.5	8.1	0.6	(3.6)
Earnings attributable to Class A and Class B shares		**259.3**	305.0	237.1	227.4	200.1
BALANCE SHEET						
Property, plant, and equipment		**4,809.4**	4,657.0	4,363.5	4,007.4	3,848.0
Total assets		**6,070.5**	5,934.4	5,404.0	5,403.9	4,538.5
Capitalization:						
Notes payable		**–**	–	4.6	197.1	80.7
Long term debt		**1,805.3**	1,916.9	1,855.9	1,865.5	1,716.2
Non-recourse long term debt		**806.1**	821.1	673.8	360.0	395.4
Preferred shares		**–**	–	–	–	50.0
Equity preferred shares		**636.5**	486.5	336.5	336.5	320.6
Share owners' equity*		**1,951.6**	1,830.1	1,643.8	1,526.5	1,419.0
Total capitalization		**5,199.5**	5,054.6	4,514.6	4,285.6	3,981.9
CASH FLOWS						
Operations		**525.8**	504.6	532.2	490.2	465.2
Purchase of property, plant and equipment		**495.7**	569.8	735.3	451.3	367.3
Financing (excluding Class A and B dividends)		**(10.6)**	384.3	62.0	189.5	39.8
Class A and B dividends		**129.3**	124.2	119.0	114.0	109.0
CLASS A & B SHARES						
Shares outstanding at end of year* (thousands)		**63,384**	63,412	63,317	63,306	63,349
Return on equity*		**13.7%**	17.6%	15.0%	15.4%	14.5%
Earnings per share* ($)		**4.09**	4.81	3.74	3.59	3.16
Dividends paid per share* ($)		**2.04**	1.96	1.88	1.80	1.72
Equity per share* ($)		**30.79**	28.86	25.96	24.11	22.40
Stock market record – Class A non-voting shares ($)	High	**59.60**	60.10	56.05	51.45	49.35
	Low	**45.10**	48.80	44.50	31.00	32.35
	Close	**57.86**	51.21	49.75	51.00	39.00
Stock market record – Class B common shares ($)	High	**58.75**	60.50	54.20	51.15	49.25
	Low	**45.50**	49.00	44.95	31.10	32.50
	Close	**58.00**	52.65	49.00	50.55	39.25

* Includes Class A non-voting shares and Class B common shares.

Consolidated Five Year Operating Summary

(millions of Canadian dollars, except as indicated)	**2003**	2002	2001	2000	1999
Utilities					
Natural gas operations					
Purchase of property, plant and equipment	**141.0**	103.1	84.6	87.6	86.9
Pipelines (thousands of kilometres)	**34.2**	33.7	33.5	33.5	33.0
Maximum daily demand (terajoules)	**1,831**	1,670	1,470	1,737	1,595
Sales (petajoules)	**198**	201	187	209	192
Transportation (petajoules)	**32**	31	22	18	13
Total system throughput (petajoules)	**230**	232	209	227	205
Average annual use per residential customer (gigajoules)	**134**	136	131	148	138
Degree days – Edmonton *	**4,245**	4,274	3,661	4,210	3,774
– Calgary **	**4,291**	4,470	3,994	4,441	3,869
Customers at year-end (thousands)	**887.8**	862.0	837.7	816.1	798.4
Electric operations					
Purchase of property, plant and equipment	**173.3**	171.4	154.3	114.5	101.2
Power lines (thousands of kilometres)	**67.0**	67.1	64.2	58.6	57.9
Retail sales (millions of kilowatt hours)	**9,768**	10,224	10,108	10,392	10,068
Average annual use per residential customer (kWh)	**7,261**	7,445	7,270	7,444	7,367
Customers at year-end (thousands)	**202.3**	197.8	192.0	191.0	186.8
Power Generation					
Purchase of property, plant and equipment	**131.7**	236.0	384.2	155.5	119.8
Generating capacity (thousands of kilowatts)	**2,397**	2,036	2,036	668	514
Logistics and Energy Services					
Purchase of property, plant and equipment	**37.5**	48.9	101.9	84.7	51.4
Pipelines (thousands of kilometres)	**8.3**	8.3	8.2	7.9	7.9
Contract demand for pipelines system access (terajoules/day)	**4,599**	4,890	4,876	4,559	4,378
Natural gas processed (Mmcf/day)	**399**	420	429	366	332
Natural gas gathering lines (kilometres)	**1,000**	940	940	670	500

* Degree days – Edmonton – are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.

** Degree days – Calgary – are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

Forward looking information

Certain statements contained in this report constitute forward-looking statements. Forward-looking statements are often, but not always identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, the report may contain forward-looking statements pertaining to purchase obligations, planned capital expenditures, anticipated completion dates and construction costs of major projects, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, and prevailing economic conditions, as well as other factors, many of which are beyond the control of the Corporation.

Board of Directors

Robert T. Booth

Robert T. Booth (2) (3)
Partner, Bennett Jones LLP,
Calgary, Alberta

Mr. Booth is a partner in the law firm Bennett Jones LLP, based in Calgary, Alberta, and brings an extensive background in energy and natural resource law to the Canadian Utilities Limited Board. A member of the Law Society of Alberta and the Canadian Bar Association, Mr. Booth obtained a Bachelor of Engineering degree from the Royal Military College of Canada, Kingston, Ontario and an LLB from Dalhousie University, Halifax, Nova Scotia.

William L. Britton

William L. Britton, Q.C. (1)
Partner, Bennett Jones LLP,
Calgary, Alberta

Mr. Britton is a Partner at Bennett Jones LLP, Calgary, Alberta, and Vice Chairman of the Board, Canadian Utilities Limited. He was Chairman and/or Managing Partner of Bennett Jones during the period from 1981 to 1997. Mr. Britton was first elected to the Board of Directors of ATCO Ltd. in September 1975 and became a Director of Canadian Utilities Limited in June 1980. Mr. Britton is Chairman of the ATCO and CU Corporate Governance Committee (GOCOM). He is also a Director of Akita Drilling Ltd., Forest Oil Ltd., Denver Broncos Football Club, Hanzell Vineyards Ltd., Geary-Market Investment Company Ltd., The Yukon Electrical Company Limited, Barking Power Limited, Thames Power Limited, as well as numerous other organizations.

Brian P. Drummond

Brian P. Drummond (1) (4)
Corporate Director,
Montreal, Quebec

Mr. Drummond is a Corporate Director based in Montreal, Quebec and most recently was Vice Chairman, Richardson Greenshields of Canada Limited. He was also previously President and Chairman of the Executive Committee of Greenshields Incorporated. Mr. Drummond is a Director and member of the Executive Committee of the McGill University Health Centre Foundation and is a Director of the Montreal General Hospital Foundation. Mr. Drummond is a past Chairman of the Investment Dealers Association of Canada and the Montreal Exchange. Mr. Drummond was first elected to the Board of ATCO Ltd. in 1968, when the company initially went public, and to the Board of Canadian Utilities Limited in 1997.

Basil K. French

Basil K. French (2) (3)
President, Karusel Management Ltd., Calgary, Alberta

Mr. French is the President of Karusel Management Ltd., a Calgary based company specializing in management consulting and property management. Prior to the establishment of Karusel Management, Mr. French was with the firms of Buchanan, Barry, Miller and French Chartered Accountants and Price Waterhouse & Co. Mr. French is the Chairman of Canadian Utilities Audit Committee and is a Director of all ATCO and Canadian Utilities subsidiaries and the five ATCO Business Groups. Mr. French was elected to the Boards of ATCO Ltd. in November 1982 and Canadian Utilities Limited in April 1981.

Board of Directors


Linda A. Heathcott

Linda A. Heathcott (4)
Executive Vice President,
Spruce Meadows, Calgary,
Alberta

Mrs. Heathcott is Executive Vice President of Spruce Meadows. A former professional equestrian rider, Mrs. Heathcott was a member of the Canadian Equestrian Team for nine years and competed in the 1996 Olympic Summer Games in Atlanta, Georgia. On January 1, 2004, Mrs. Heathcott was elected Deputy Chairman of AKITA Drilling Ltd. Mrs. Heathcott also serves on the Boards of Calgary Olympic Development Authority, Sentgraf Enterprises Ltd. and a number of ATCO Group subsidiary Boards. She was elected to the Board of Canadian Utilities Limited in May, 2000.


William R. Horton

William R. Horton, P.Eng. (2) (3)
Corporate Director, Winfield,
British Columbia

Mr. Horton, was Chairman of Horton Engineering Ltd. of Edmonton, which provided engineering, economic and financial consulting services to government and industry, primarily related to public utilities. Mr. Horton was a member of the Alberta Public Utilities Board from 1973 to 1976 and was Chairman from 1976 to 1983. Mr. Horton has been a Director of Canadian Utilities Limited since 1984 when he joined the Company as Executive Vice President, and President of Canadian Utilities Limited utility subsidiaries. In 1988, Mr. Horton was appointed to the additional post of Deputy Chairman of Canadian Utilities Limited utility subsidiaries, a position he held until his retirement in 1990.


Helmut M. Neldner

Helmut M. Neldner (1) (2) (3) (4)
Corporate Director,
Westerose, Alberta

Mr. Neldner is a Corporate Director based in Westerose, Alberta. He has extensive experience in the telecommunications industry and is the former President & Chief Executive Officer of AGT and Telus Corporation. He serves on several Boards of Directors including ATCO Ltd. and Canadian Utilities Limited, as well as the five ATCO Business Groups. He was nominated and elected to the Canadian Utilities Limited Board in May 1991 and the ATCO Ltd. Board in May 1997. Mr. Neldner is the Chairman of the ATCO and CU Risk Review Committee.


Larry R. Shaben

Larry R. Shaben
Chairman, Western New
Ventures Capital Corporation,
Edmonton, Alberta

Mr. Shaben is the Chairman of Western New Ventures Capital Corporation, based in Edmonton, Alberta and previously was Vice Chairman, Petrovalve International Inc. In 1989, Mr. Shaben retired from active political life to resume his business activities in the private sector. During his time with the Alberta government, he held several ministerial portfolios including Minister of Economic Development & Trade, Minister of Housing, and Minister of Utilities and Telephones. Mr. Shaben was nominated and elected to the Board of Directors of Canadian Utilities Limited in May 1995.

Board of Directors

Nancy C. Southern

Nancy C. Southern
President and Chief Executive Officer, Canadian Utilities Limited.

Nancy Southern was appointed President & Chief Executive Officer, ATCO Ltd. and Canadian Utilities Limited, effective January 1, 2003. Previously she had been Co-Chairman & Chief Executive Officer since January 2000, Deputy Chief Executive Officer since May 1998 and Deputy Chairman since January 1996 of ATCO Group. She has been a Director of the Corporation since 1990. Ms. Southern has full responsibility for executing strategic direction and the on-going operations of the corporation, reporting to the Board of Directors. She is currently a Director of ATCO Ltd. and Canadian Utilities Limited and serves on the Boards of all the ATCO Group subsidiary companies. She is also a Director of the Bank of Montreal, Shell Canada Limited, Akita Drilling Ltd., and Sentgraf Enterprises Ltd.

Ronald D. Southern

Ronald D. Southern
C.B.E., O.C., LL.D.
Chairman of the Board of Directors, Canadian Utilities Limited.

Ron Southern is Chairman of the Board of ATCO Ltd., Canadian Utilities and all ATCO Group subsidiary companies. Together with his late father, S.D. Southern, Mr. Southern founded ATCO Group in 1947 and served as the company's President for 48 years. He is credited with transforming the company to what it is today — one of Canada's premier corporations with assets of $6.6 billion and employing more than 7,000 people. Mr. Southern also serves as Chairman of Akita Drilling Ltd. and Sentgraf Enterprises Ltd.

D. Logan Tait

D. Logan Tait, [3] [4]
F.R.I., F.C.A.
President, Tait Management Services, Lethbridge, Alberta

Mr. Logan Tait is a Partner of Meyers Norris Penny LLP, Chartered Accountants and Business Advisors in the Lethbridge, Alberta office and is President of Tait Management Services, a consulting firm which provides accounting services and tax advice. He has been active in the Canadian and Alberta Real Estate Association and Junior Achievement of Southern Alberta and was elected a Fellow of Chartered Accountants in 1986. He was elected to the Board of Canadian Western Natural Gas in 1980 and Canadian Utilities Limited in May 1992.

Gordan Tallman

Gordon Tallman [2]
Corporate Director,
Calgary, Alberta

Mr. Tallman, former Senior Vice President, Royal Bank, Prairies Region, recently retired after a career spanning 42 years. Some of his key management responsibilities with the Bank included Vice President, Global Energy Group, Vice President Commercial Banking & National Accounts and Senior Vice President, Lending — Risk Management, Group Chief Auditor. He serves on the Boards of Big Rock Brewery, P.F.B. Corporation, Investment Saskatchewan Inc. and is Chairman of the Boards of C.V. Technologies, Inc. and Enbridge Income Fund. Mr. Tallman joined the Board of Canadian Utilities in May 2003.

Charles W. Wilson

Charles W. Wilson (2) (3)
Corporate Director,
Evergreen, Colorado

Mr. Wilson is former President, Chief Executive Officer and Director of Shell Canada Limited and former President and Director of Shell Investments Limited (Canada). Mr. Wilson graduated from the University of New Mexico with his Master of Science in Engineering and held several senior executive positions in Refining & Marketing, Chemical, Oil & Gas Production and Corporate Planning during his career at Shell. He was elected to the Board of Canadian Utilities Limited in May 2000 and ATCO Ltd. in May 2002 and to the Akita Drilling Board and Talisman Energy Board in 2002. He also serves on the Big Rock Brewery Board. Mr. Wilson also sits on the Board for the Power Generation and Logistics and Energy Services Business Groups.

1 Member of the Corporate Governance — Nomination, Succession and Compensation Committee
2 Member of the Audit Committee
3 Member of the Risk Review Committee
4 Member of the Pension Fund

Officers

Ronald D. Southern
Chairman of the Board

William L. Britton, Q.C.
Vice Chairman of the Board

Nancy C. Southern
President & Chief Executive Officer

James A. Campbell
Senior Vice President, Finance & Chief Financial Officer

Susan R. Werth
Senior Vice President & Chief Administration Officer

Brian M. Andrews
Vice President

Dale R. Cawsey
Vice President, Human Resources
& Corporate Secretary

D. Terrence Davis
Vice President, Internal Audit

Siegfried W. Kiefer
Vice President, Information Technology
& Chief Information Officer

Walter A. Kmet
Vice President

Charles S. McConnell
Treasurer

Pat Spruin
Assistant Corporate Secretary
& Manager Corporate Secretarial

Ladis J. Vegh
Vice President, Insurance

Karen M. Watson
Vice President, Finance & Controller

MANAGING DIRECTORS AND PRESIDENTS OF PRINCIPAL OPERATING SUBSIDIARIES

Gary K. Bauer
Managing Director, Power Generation
President, ATCO Power Ltd.
(retired February 2, 2004)

Paul F. Blaha
President, Genics Inc.

Richard (Rick) J. Brouwer
President, ATCO Midstream Ltd.

Jerome F. Engler
President, ATCO Gas

J. Richard (Dick) Frey
Managing Director, Utilities

J. Douglas (Doug) Graham
President, ATCO Pipelines

Siegfried W. Kiefer
Managing Director, Technologies

Roberta (Bobbi) L. Lambright
President, ATCO I-Tek Inc.

R.L. Vaughan Payne
President, ATCO Travel Ltd.

Joseph (Joe) J. Schnitzer
President, ASHCOR Technologies Ltd.

Michael M. Shaw
Managing Director, Logistics & Energy Services

Richard (Dick) H. Walthall
President, ATCO Electric Ltd.

Gerry W. Welsh
President & Chief Operating Officer, ATCO Power Ltd.
(effective February 2, 2004)

Harry G. Wilmot
President, ATCO Frontec Corp.

General Information

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Wednesday, May 12, 2004 at The Fairmont Hotel Macdonald, 10065 - 100 Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A Non-Voting and
Class B Common Shares and
Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU
Class B common Symbol CU.X
Listing: The Toronto Stock Exchange

CUMULATIVE REDEEMABLE SECOND PREFERRED SHARES
5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
1400, 909 - 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: **www.canadian-utilities.com**

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning Shares should be directed to:
CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 - 7th Avenue SW
Calgary, Alberta T2P 2Z1
Telephone: 1-800-387-0825
e-mail: inquiries@cibcmellon.com
Website: **www.cibcmellon.com**

Printed in Canada

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

1400, 909 - 11th Avenue SW, Calgary, Alberta T2R IN6

Telephone: (403) 292-7500

Fax: (403) 292-7623

www.canadian-utilities.com

part-2

2003

Financial Information

CANADIAN UTILITIES LIMITED
An ATCO Company

Consolidated Financial Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations

Table of Contents

CANADIAN UTILITIES LIMITED
FINANCIAL ACHIEVEMENT IN 2003

- Earnings per share increased to $4.09 from $3.75 in 2002, excluding the gain on sale of the Viking-Kinsella property ($1.06 per share) – the 14th consecutive year of increased earnings per share, excluding the gain on sale of the Viking-Kinsella property in 2002. 2002 earnings per share in total were $4.81.

- Dividends paid per Class A and Class B share increased by $0.08 to $2.04 from $1.96 in 2002 – dividends have increased each year since 1972 – 31 years!

- Earnings increased by $21.6 million to $259.3 million in 2003 compared to $237.7 million in 2002, excluding the gain on sale of the Viking-Kinsella property ($67.3 million). 2002 earnings in total were $305.0 million.

- Cash flow from operations increased by $21.2 million to $525.8 million.

- Total assets increased by $137 million to $6.071 billion compared to $5.934 billion in 2002.

- Capital expenditures were $496 million in 2003 compared to $570 million in 2002. Over the previous five years, capital expenditures averaged $524 million per year.

- Long term debt decreased by $112 million to $1.805 billion.

- Non-recourse long term debt decreased by $15 million to $852 million.

- Equity preferred shares increased by $150 million to $637 million.

- Share owners' equity increased by $122 million to $1.952 billion compared to $1.830 billion in 2002.

- Return on common equity was 13.7% compared to 17.6% in 2002.

- Financing activities in 2003 included the issue of $150 million of 6.0% equity preferred shares.

- CU redeemed $60 million of 7.25% debentures and $79 million of other debt in 2003, and issued $25 million of other debt in 2003.

- Non-recourse long term debt of $41 million was issued in 2003 for the Brighton Beach Power Project, while CU redeemed $38 million of non-recourse long-term debt in 2003.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised of six non-management Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

J.A. Campbell
Senior Vice President, Finance and Chief Financial Officer

K.M. Watson
Vice President, Finance and Controller

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2003 and 2002 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 6, 2004, except as to note 21,
which is as of February 17, 2004

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31 **2003**	Three Months Ended December 31 2002	Year Ended December 31 **2003**	Year Ended December 31 2002
		(Unaudited)			
Revenues		**$ 950.3**	$ 930.7	**$3,742.6**	$2,975.9
Costs and expenses					
Natural gas supply		**368.6**	358.1	**1,519.8**	991.7
Purchased power		**46.8**	59.6	**209.8**	184.4
Operation and maintenance		**216.1**	219.1	**858.4**	759.9
Selling and administrative		**52.7**	38.2	**158.1**	136.0
Depreciation and amortization		**72.7**	67.9	**268.9**	244.4
Interest	10	**47.1**	45.3	**190.3**	184.1
Franchise fees		**30.5**	28.9	**122.6**	98.5
		834.5	817.1	**3,327.9**	2,599.0
		115.8	113.6	**414.7**	376.9
Gain on sale of Viking-Kinsella property	2	**-**	1.6	**-**	110.1
Interest and other income	3	**9.5**	7.8	**33.4**	26.1
Earnings before income taxes		**125.3**	123.0	**448.1**	513.1
Income taxes	4	**29.7**	44.3	**155.7**	189.9
		95.6	78.7	**292.4**	323.2
Dividends on equity preferred shares		**8.9**	5.2	**33.1**	18.2
Earnings attributable to Class A and Class B shares	2	**86.7**	73.5	**259.3**	305.0
Retained earnings at beginning of period		**1,385.3**	1,275.2	**1,314.9**	1,136.9
		1,472.0	1,348.7	**1,574.2**	1,441.9
Dividends on Class A and Class B shares		**32.3**	31.0	**129.3**	124.2
Direct charges	5	**0.9**	2.8	**6.1**	2.8
Retained earnings at end of period		**$1,438.8**	$1,314.9	**$1,438.8**	$1,314.9
Earnings per Class A and Class B share	13	**$ 1.37**	$ 1.16	**$ 4.09**	$ 4.81
Diluted earnings per Class A and Class B share	13	**$ 1.36**	$ 1.15	**$ 4.07**	$ 4.79
Dividends paid per Class A and Class B share		**$ 0.51**	$ 0.49	**$ 2.04**	$ 1.96

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

	Note	December 31 2003	2002
ASSETS			
Current assets			
Cash and short term investments	16	**$ 328.1**	$ 438.9
Accounts receivable		**540.6**	459.4
Inventories		**171.3**	121.7
Income taxes recoverable		**10.2**	20.2
Deferred natural gas costs		**27.2**	31.2
Deferred electricity costs		**-**	20.7
Prepaid expenses		**25.6**	25.4
		1,103.0	1,117.5
Property, plant and equipment	6	**4,809.4**	4,657.0
Security deposits for debt		**23.1**	26.1
Other assets	7	**135.0**	133.8
		$6,070.5	$5,934.4
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness		**$ -**	$ 5.0
Accounts payable and accrued liabilities		**478.8**	451.3
Future income taxes	4	**11.5**	16.8
Deferred electricity cost recoveries		**1.0**	-
Deferred electricity cost obligation	9	**-**	51.0
Non-recourse long term debt due within one year	10	**46.3**	46.1
		537.6	570.2
Future income taxes	4	**227.0**	230.8
Deferred credits	11	**106.4**	78.8
Long term debt	10	**1,805.3**	1,916.9
Non-recourse long term debt	10	**806.1**	821.1
Equity preferred shares	12	**636.5**	486.5
Class A and Class B share owners' equity			
Class A and Class B shares	13	**510.5**	509.6
Retained earnings		**1,438.8**	1,314.9
Foreign currency translation adjustment		**2.3**	5.6
		1,951.6	1,830.1
		$6,070.5	$5,934.4

N.C. Southern

N.C. SOUTHERN
DIRECTOR

B.K. French

B.K. FRENCH
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2003	Three Months Ended December 31 2002	Year Ended December 31 2003	Year Ended December 31 2002
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 86.7**	$ 73.5	**$ 259.3**	$ 305.0
Adjustments for:					
Depreciation and amortization		**72.7**	67.9	**268.9**	244.4
Future income taxes		**(6.2)**	22.3	**(0.3)**	20.7
Gain on sale of Viking-Kinsella property - net of current income taxes	2	**-**	(0.6)	**-**	(67.3)
Other - net		**0.1**	8.4	**(2.1)**	1.8
Cash flow from operations		**153.3**	171.5	**525.8**	504.6
Changes in non-cash working capital	15	**(82.8)**	(58.6)	**(52.8)**	(160.0)
		70.5	112.9	**473.0**	344.6
Investing activities					
Purchase of property, plant and equipment		**(176.7)**	(155.1)	**(495.7)**	(569.8)
Sale of Viking-Kinsella property - net of current income taxes	2	**-**	0.8	**-**	107.7
Proceeds on disposal of other property, plant and equipment		**11.3**	1.0	**23.8**	1.7
Contributions by utility customers for extensions to plant		**13.8**	21.2	**48.1**	41.1
Non-current deferred electricity costs		**10.3**	(10.4)	**19.1**	18.7
Changes in non-cash working capital	15	**15.3**	(4.8)	**(30.0)**	(8.3)
Other		**1.0**	1.0	**0.7**	(10.4)
		(125.0)	(146.3)	**(434.0)**	(419.3)
Financing activities					
Change in notes payable		**(42.0)**	(7.2)	**-**	(4.6)
Deferred electricity cost obligation	9	**-**	(14.9)	**(51.0)**	51.0
Issue of long term debt		**12.0**	300.0	**25.5**	300.0
Issue of non-recourse long term debt		**-**	4.8	**40.7**	173.0
Repayment of long term debt		**(66.8)**	(200.8)	**(139.1)**	(241.9)
Repayment of non-recourse long term debt		**(5.5)**	(4.5)	**(38.0)**	(43.7)
Issue of equity preferred shares		**-**	150.0	**150.0**	150.0
Issue (purchase) of Class A shares		**0.1**	0.1	**(2.4)**	2.9
Dividends paid to Class A and Class B share owners		**(32.3)**	(31.0)	**(129.3)**	(124.2)
Changes in non-cash working capital	15	**1.7**	0.6	**7.9**	8.7
Other		**(2.4)**	(11.3)	**(4.2)**	(11.1)
		(135.2)	185.8	**(139.9)**	260.1
Foreign currency translation		**0.6**	1.4	**(4.9)**	5.6
Cash position [1]					
Increase (decrease)		**(189.1)**	153.8	**(105.8)**	191.0
Beginning of period		**517.2**	280.1	**433.9**	242.9
End of period		**$ 328.1**	$ 433.9	**$ 328.1**	$ 433.9

[1] Cash position includes cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2003
(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments ("Canadian Utilities"). Principal operations are Utilities (ATCO Electric, ATCO Gas), Power Generation (ATCO Power, Alberta Power (2000)), Logistics and Energy Services (ATCO Pipelines, ATCO Midstream, ATCO Frontec) and Technologies (ATCO I-Tek Business Services, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants.

Certain comparative figures have been reclassified to conform to the current presentation.

Regulation

ATCO Electric, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations".

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the Alberta Energy and Utilities Board ("AEUB"), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination.

The generating plants of Alberta Power (2000) were regulated by the AEUB until December 31, 2000 but are now governed by legislatively mandated Power Purchase Arrangements ("PPA") that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Use of Estimates

The preparation of Canadian Utilities' consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

Revenues from sales of natural gas and electricity by the regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but not yet billed. Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. PPA incentives and penalties are recognized as described under the accounting policy for deferred availability incentives.

1. Summary of significant accounting policies (continued)

Revenues from the transportation and storage of natural gas are recognized on the basis of contractual arrangements for access. Revenues from sales of marketed natural gas and other energy products are recognized upon delivery. Revenues from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense is based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers and revenues and natural gas supply expense are adjusted accordingly.

Purchased Power

Purchased power expense is based on the actual cost of electricity purchased, whereas the amount included in customer rates is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Certain regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets are approved by the AEUB or, in the case of Alberta Power (2000)'s generating plants, are determined by the PPA's. These depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

1. **Summary of significant accounting policies** (continued)

When events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the carrying value is compared to the estimated future net cash flows from its use together with its residual value. Any excess of the carrying value over the net recoverable amount is expensed.

Deferred Financing Charges

Issue costs of long term debt are amortized over the weighted average life of the debt and issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

Under the terms of the PPA's, Canadian Utilities is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to Canadian Utilities by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by Canadian Utilities to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Long Term Debt Due Within One Year

When Canadian Utilities intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on Canadian Utilities' behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

During 2003, Canadian Utilities adopted the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline pertaining to the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting.

In conducting its business, Canadian Utilities uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

Canadian Utilities designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. Canadian Utilities also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

1. Summary of significant accounting policies (continued)

Employee Future Benefits

Canadian Utilities accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Canadian Utilities Limited stock option plan and share appreciation rights are described in Note 14.

While the recommendations of the CICA on accounting for stock based compensation and other stock based payments require the adoption on or before January 1, 2004 of the fair value based method of accounting for stock options, other methods of accounting are permitted until that date. Canadian Utilities has chosen to retain its existing accounting policy, which is permitted by the recommendations, whereby no compensation expense is recognized upon the granting or exercise of stock options. Any consideration paid by holders of the stock options upon exercise is credited to share capital. While the recommendations require expense recognition for options that may be settled in cash or other assets, Canadian Utilities amended its stock option policy in June 2002 so that stock options will no longer be repurchased. Prior to that date, if stock options were repurchased, the consideration paid to the holders of the options was charged to retained earnings.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, any change in compensation expense is recognized monthly in earnings.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment in share owners' equity.

Transactions denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

2. Gain on sale of Viking-Kinsella property

In 2002, Canadian Utilities sold its Viking-Kinsella natural gas producing property, which had a net book value of approximately $40 million, for $550 million. In accordance with an AEUB decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments.

Canadian Utilities' share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million, before income taxes of $42.8 million. This sale increased earnings by $67.3 million.

3. Interest and other income

	2003	2002
Interest	**$24.3**	$17.1
Allowance for funds used by regulated operations	**4.4**	3.6
Other	**4.7**	5.4
	$33.4	$26.1

4. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2003		2002	
Earnings before income taxes	**$448.1**	%	$513.1	%
Income taxes, at statutory rates	**$187.0**	**41.7**	$216.7	42.2
Federal general tax reduction [1]	**(10.9)**	**(2.4)**	(9.1)	(1.8)
Manufacturing and processing tax credit	**(8.1)**	**(1.8)**	(7.3)	(1.4)
Resource allowance	**(3.5)**	**(0.8)**	(3.3)	(0.6)
Crown royalties and other non-deductible Crown payments	**1.1**	**0.3**	1.8	0.3
Large Corporations Tax	**8.1**	**1.8**	7.1	1.4
Foreign tax rate variance	**(2.6)**	**(0.6)**	(5.2)	(1.0)
Non-deductible interest on foreign financing	**1.5**	**0.3**	1.4	0.3
Change in future income taxes resulting from reduction in tax rates	**(2.1)**	**(0.5)**	(1.8)	(0.4)
Unrecorded future income taxes relating to regulated operations	**7.1**	**1.6**	4.9	1.0
Natural gas and other property disposals	**(0.6)**	**(0.1)**	(10.8)	(2.1)
Reduction in future income taxes resulting from a change in tax legislation in Australia	**(8.9)**	**(2.0)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(6.8)**	**(1.5)**	-	-
Other	**(5.6)**	**(1.2)**	(4.5)	(0.9)
	155.7	**34.8**	189.9	37.0
Current income taxes	**158.6**		151.4	
Future income taxes (recoveries)	**$ (2.9)**		$ 38.5	

[1] The federal general tax reduction of 5% (2002 — 3%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. Effective January 1, 2003, an additional federal tax reduction of 1% is applicable to earnings that have benefited from the resource allowance.

4. Income taxes (continued)

The future income tax liabilities (assets) comprise the following:

	2003	2002
Property, plant and equipment	**$215.5**	$239.1
Deferred assets and liabilities	**36.6**	24.5
Tax loss carryforwards	**(1.2)**	(0.8)
Income tax reassessment	**(12.9)**	(12.9)
Other	**0.5**	(2.3)
	238.5	247.6
Less: Amounts included in current future income taxes	**11.5**	16.8
	$227.0	$230.8

Unrecorded future income tax liabilities of the regulated operations amounted to $167.5 million at December 31, 2003. This balance includes $46.3 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards, which do not expire, have been recorded in the amount of $1.2 million. In addition, there are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2007.

Income taxes paid amounted to $147.2 million (2002 — $277.1 million).

In 2001, Canadian Utilities received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. Management did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities. During 2003, Canadian Utilities was successful in appealing the reassessment to the Tax Court of Canada. However, the Federal Government has commenced an appeal of the Tax Court's decision with the Federal Court of Appeal. Consequently, the future income tax reduction of $12.9 million has not been adjusted.

5. Direct charges to retained earnings

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
	(Unaudited)			
Issue costs of equity preferred shares (after income taxes)	**$ -**	$2.8	**$2.7**	$2.8
Purchase of Class A shares	**0.9**	-	**3.4**	-
	$0.9	$2.8	**$6.1**	$2.8

6. Property, plant and equipment

	2003			2002	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$4,313.5**	**$1,618.2**	$4,098.3	$1,546.4
Power generation	3.4%	**2,694.2**	**784.4**	2,588.5	715.7
Logistics and energy services	3.8%	**1,069.7**	**381.3**	1,043.9	352.3
Other	16.0%	**67.4**	**36.9**	62.8	33.1
		$8,144.8	**2,820.8**	$7,793.5	2,647.5
Property, plant and equipment less accumulated depreciation			**5,324.0**		5,146.0
Unamortized contributions by utility customers for extensions to plant			**514.6**		489.0
			$4,809.4		$4,657.0

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $277.6 million (2002 — $259.4 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $265.8 million (2002 — $550.0 million) and non-depreciable assets of $39.3 million (2002 — $32.7 million).

7. Other assets

	2003	2002
Net accrued pension asset (Note 18)	**$ 52.5**	$ 48.0
Costs deferred for recovery through future regulated rates	**25.7**	27.6
Deferred costs related to disposition of retail energy businesses	**10.8**	8.5
Deferred financing charges	**27.9**	29.5
Deferred electricity costs	**-**	3.0
Other	**18.1**	17.2
	$135.0	$133.8

8. Credit lines

At December 31, 2003, Canadian Utilities has the following credit lines that enable it to obtain financing for general business purposes:

	2003			2002		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$ 350.0**	**$16.2**	**$ 333.8**	$ 350.0	$ 56.2	$ 293.8
Short term committed	**624.3**	**49.8**	**574.5**	627.7	52.9	574.8
Uncommitted	**178.5**	**14.1**	**164.4**	225.0	10.1	214.9
	$1,152.8	**$80.1**	**$1,072.7**	$1,202.7	$119.2	$1,083.5

9. Deferred electricity cost obligation

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers, and permitting ATCO Electric to sell these deferred costs and related rights.

9. Deferred electricity cost obligation (continued)

In 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. GAAP required that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received resulted in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bore interest at 3.3975%, which approximated the interest earned on the deferred costs. The obligation principal and interest incurred were paid to the purchaser as the deferred costs and interest earned were collected from customers. At December 31, 2003, the outstanding obligation was nil (2002 — $51.0 million).

10. Long term debt and non-recourse long term debt

Long term debt

	2003	2002
CU Inc. debentures – unsecured		
1993 Series 7.25% due September 2003	$ -	$ 60.0
1994 Series 8.73% due June 2004	**100.0**	100.0
1995 Series 8.43% due June 2005	**125.0**	125.0
2001 4.84% due November 2006	**175.0**	175.0
2002 4.801% due November 2007	**50.0**	50.0
2000 6.97% due June 2008	**100.0**	100.0
1989 Series 10.20% due November 2009	**125.0**	125.0
1990 Series 11.40% due August 2010	**125.0**	125.0
2000 7.05% due June 2011	**100.0**	100.0
2002 6.145% due November 2017	**150.0**	150.0
1999 Series 6.8% due August 2019	**300.0**	300.0
1990 Second Series 11.77% due November 2020	**100.0**	100.0
1991 Series 9.92% due April 2022	**125.0**	125.0
1992 Series 9.40% due May 2023	**100.0**	100.0
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	**100.0**	100.0
	1,775.0	1,835.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, due July 2004, payable in Australian dollars, unsecured (1)	**13.8**	21.4
ATCO Midstream Ltd. credit facility, at BA rates	**-**	8.0
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash (1)	**12.0**	48.0
Other long term obligation, at 5.0%, due June 2005, unsecured	**4.5**	4.5
	$1,805.3	$1,916.9

On January 20, 2004, CU Inc. issued $180.0 million of 5.432% Debentures for cash.

Non-recourse long term debt

	2003	2002
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	**$ 80.8**	$ 97.1
At LIBOR, due to 2010 (1)	**132.5**	159.2
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	**0.1**	2.6
At 6.825%, due to 2013 (1)	**51.6**	48.9

10. Long term debt and non-recourse long term debt (continued)

***Non-recourse long term debt** (continued)*

	2003	2002
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.29% to 2008, at LIBOR thereafter, due to 2016 (1)	**6.4**	7.7
At 7.067% to 2008, at LIBOR thereafter, due to 2016 (1)	**9.0**	10.8
At 7.25% to 2011, at LIBOR thereafter, due to 2016 (1)	**93.1**	95.6
Joffre project financing:		
At 6.435% to 2004, at BA rates thereafter, due to 2012 (1)	**2.3**	3.6
At 7.161%, due to 2012 (1)	**33.4**	35.6
At 8.59%, due to 2020	**32.0**	32.0
Scotford project financing:		
At 5.102%, due to 2008, at BA rates thereafter, due to 2014 (1)	**53.7**	-
At 5.102%, due to 2008, at LIBOR thereafter, due to 2014 (1)	**13.9**	-
At BA rates, due to 2014 (1)	**-**	54.7
At LIBOR, due to 2014 (1)	**-**	13.9
At 7.93%, due to 2022	**28.2**	28.4
Muskeg River project financing:		
At 5.147%, due 2007, at BA rates thereafter, due to 2014 (1)	**51.0**	53.1
At BA rates, due to 2014 (1)	**0.6**	-
At 7.56%, due to 2022	**34.9**	35.8
Brighton Beach project financing:		
At 5.325%, due to 2019 (1)	**40.7**	-
At 6.924%, due to 2024	**110.6**	110.6
Cory project financing:		
At BA rates, due to 2011 (1)	**0.1**	-
At 6.461%, due to 2011 (1)	**4.7**	4.8
At 7.586%, due to 2024	**38.8**	38.8
At 7.601%, due to 2026	**34.0**	34.0
	852.4	867.2
Less: Amounts due within one year	**46.3**	46.1
	$806.1	$821.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 0.9% (2002 — 1.0%).

Canadian Utilities has fixed interest rates, either directly or through interest rate swap agreements, on 92% (2002 — 89%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2003 was $1,248.2 million (2002 — $1,203.8 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

10. Long term debt and non-recourse long term debt (continued)

a) **Equity contributions** — Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $35.3 million.

b) **Completion of construction** — Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is $161.2 million, with an expiry date of September 30, 2006.

c) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2003, $0.4 million was payable for the Muskeg River and Scotford projects.

d) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2003, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$6.7
Joffre project financing	Nil [2]	$4.8
Muskeg River project financing	Nil [1]	$5.3
Scotford project financing	Nil [1]	$5.3

(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $1.4 million met with project cash flows.

e) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2003, the maximum value of the guarantee is $33.6 million.

f) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

10. Long term debt and non-recourse long term debt (continued)

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:

- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2003, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. Canadian Utilities Limited has guaranteed ATCO Power's obligation to remediate certain deficiencies at the Oldman River project in the amount of $2.4 million. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory project.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects. The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long term Debt	Total
2004	$113.8	$ 46.3	$160.1
2005	129.5	50.5	180.0
2006	175.0	68.0	243.0
2007	62.0	55.9	117.9
2008	100.0	81.0	181.0
	$580.3	$301.7	$882.0

Of the $160.1 million due in 2004, $113.8 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

10. Long term debt and non-recourse long term debt (continued)

Interest expense

Interest on debt is as follows:

	2003	2002
Long term debt	**$144.2**	$145.8
Non-recourse long term debt	**55.9**	49.8
Notes payable	**0.6**	0.6
Current bank indebtedness	**5.3**	8.5
Amortization of financing charges	**2.5**	2.2
Less: Capitalized on non-regulated projects	**(18.2)**	(22.8)
	$190.3	$184.1

Interest paid amounted to $207.8 million (2002 – $207.6 million).

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on Canadian Utilities' current borrowing rate for similar borrowing arrangements.

	2003	2002
Long term debt		
Fixed rate	**$2,093.3**	$2,155.0
Floating rate	**25.8**	77.4
	$2,119.1	$2,232.4
Non-recourse long term debt		
Fixed rate	**$ 757.8**	$ 597.8
Floating rate	**133.5**	283.6
	$ 891.3	$ 881.4

11. Deferred credits

	2003	2002
Deferred availability incentives	**$ 43.3**	$45.0
Deferred electricity cost recoveries	**16.2**	-
Accrued equipment repairs and maintenance	**12.1**	13.1
Net accrued post employment benefits (Note 18)	**8.7**	6.0
Other	**26.1**	14.7
	$106.4	$78.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.5 million in 2003 (2002 – nil).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, Canadian Utilities uses these estimates to forecast best case, worst case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

11. Deferred credits (continued)

Compared to the most likely scenario recorded in revenues, the best case scenario would have resulted in higher revenues of approximately $4.0 million, whereas the worst case scenario would have resulted in lower revenues of approximately $3.5 million.

12. Equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	**2003** Shares	**2003** Amount	2002 Shares	2002 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**2,277,675**	**$ 56.9**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**2,146,730**	**53.7**	2,146,730	53.7
6.6% Series S	$25.00	Open	**635,700**	**15.9**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	-	-
Perpetual Cumulative Second Preferred Shares						
5.05% Series O	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series T	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series U	$25.00	December 2, 2006	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$636.5		$486.5

On April 17, 2003, Canadian Utilities Limited issued $150.0 million Cumulative Redeemable Second Preferred Shares Series X for cash. The dividend rate has been fixed at 6.0%.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series O, T, U, and V are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $665.1 million (2002 — $472.9 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

13. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2001	39,876,769	$358.3	23,440,266	$148.4	63,317,035	$506.7
Stock options exercised	95,150	2.9	-	-	95,150	2.9
Converted: Class B to Class A	149,875	0.9	(149,875)	(0.9)	-	-
December 31, 2002	40,121,794	362.1	23,290,391	147.5	63,412,185	509.6
Purchased	(73,900)	(0.7)	-	-	(73,900)	(0.7)
Stock options exercised	45,350	1.6	-	-	45,350	1.6
Converted: Class B to Class A	1,040,465	6.6	(1,040,465)	(6.6)	-	-
December 31, 2003	**41,133,709**	**$369.6**	**22,249,926**	**$140.9**	**63,383,635**	**$510.5**

From January 1, 2004 to February 6, 2004, 29,750 Class A non-voting shares were issued with respect to the exercises of stock options.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
	(Unaudited)			
Weighted average shares outstanding	**63,371,535**	63,411,613	**63,389,192**	63,389,738
Effect of dilutive stock options	**310,985**	301,608	**275,855**	311,187
Weighted average diluted shares outstanding	**63,682,520**	63,713,221	**63,665,047**	63,700,925

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding

13. Class A and Class B shares (continued)

Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to Canadian Utilities Limited pursuant to the Canada Business Corporations Act.

Normal course issuer bid

On May 20, 2002, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The offer expired on May 19, 2003. Over the life of the offer, 17,300 shares were purchased, all of which were purchased in 2003. On May 20, 2003, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The offer will expire on May 19, 2004. From May 20, 2003, to February 6, 2004, 56,600 shares have been purchased, all of which were purchased in 2003.

14. Stock based compensation plans

Stock option plan

Canadian Utilities Limited has a stock option plan under which 3,200,000 Class A non-voting shares are reserved for issuance in respect of options. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2003		2002	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**947,800**	**$37.15**	991,550	$35.72
Granted	**42,000**	**51.74**	52,500	51.51
Exercised	**(45,350)**	**35.60**	(95,150)	30.05
Settled	**-**	**-**	(1,100)	41.93
Options at end of year	**944,450**	**$37.88**	947,800	$37.15

Information about stock options outstanding at December 31, 2003 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$23.76 - $30.08	264,700	2.2	$27.27	264,700	$27.27
$34.46 - $37.74	295,450	5.9	35.65	238,850	35.62
$41.29 - $57.29	384,300	6.2	46.88	249,300	45.86
$23.76 - $57.29	944,450	5.0	$37.88	752,850	$36.08

In 2003, Canadian Utilities Limited granted 42,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of $51.74 per share. The options have a term of ten years and vest over the first five years.

14. Stock based compensation plans (continued)

Had Canadian Utilities adopted the fair value based method of accounting for stock options granted on and after January 1, 2002, earnings would have been reduced by $0.2 million (2002 — $0.1 million), but there would have been no effect on earnings per share. The reduction in earnings was determined using the Black-Scholes option pricing model, which estimated the weighted average value of the options granted during 2003 at $4.68 per option (2002 — $7.00 per option) using the following assumptions:

	2003	2002
Risk free interest rate	**4.3 %**	4.7 %
Expected holding period prior to exercise	**5.5 years**	5.7 years
Share price volatility	**12.1 %**	14.1 %
Estimated annual Class A share dividend	**4.0 %**	3.8 %

Share appreciation rights

Directors, officers and key employees of Canadian Utilities may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on The Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $2.4 million (2002 — $0.9 million).

15. Changes in non-cash working capital

	2003	2002
Operating activities, changes related to:		
Accounts receivable	**$(92.0)**	$ (20.0)
Inventories	**(50.8)**	5.8
Deferred natural gas costs	**4.0**	(27.3)
Deferred electricity costs	**21.7**	6.7
Prepaid expenses	**(0.8)**	(10.5)
Accounts payable and accrued liabilities	**60.6**	(7.4)
Income taxes	**9.8**	(126.0)
Future income taxes	**(5.3)**	18.7
	$(52.8)	$(160.0)
Investing activities, changes related to:		
Inventories	**$ 0.5**	$ (2.0)
Prepaid expenses	**0.3**	2.0
Accounts payable and accrued liabilities	**(30.8)**	(8.3)
	$(30.0)	$ (8.3)
Financing activities, changes related to:		
Accounts receivable	**$ 7.9**	$ 7.7
Accounts payable and accrued liabilities	**-**	1.0
	$ 7.9	$ 8.7

16. Joint ventures

Canadian Utilities' interest in joint ventures is summarized below:

	2003	2002
Statement of earnings		
Revenues	**$ 420.9**	$ 378.1
Operating expenses	**291.7**	269.5
Depreciation and amortization	**34.7**	25.8
Interest	**34.5**	25.8
	60.0	57.0
Interest and other income	**5.7**	4.8
Earnings from joint ventures before income taxes	**$ 65.7**	$ 61.8
Balance sheet		
Current assets	**$ 143.1**	$ 160.2
Current liabilities	**(115.3)**	(112.7)
Property, plant and equipment	**997.5**	949.9
Deferred items – net	**(60.0)**	(83.3)
Non-recourse long term debt	**(612.6)**	(625.8)
Investment in joint ventures	**$ 352.7**	$ 288.3
Statement of cash flows		
Operating activities	**$ 80.7**	$ 55.3
Investing activities	**(105.6)**	(141.5)
Financing activities	**4.5**	74.4
Foreign currency translation	**(4.7)**	4.5
Decrease in cash position	**$ (25.1)**	$ (7.3)

Current assets include cash of $54.4 million (2002 — $76.6 million) which is only available for use within the joint ventures.

17. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, Canadian Utilities sold fuel in the amount of $2.8 million (2002 — $3.2 million), recovered administrative expenses and business development costs totaling $3.0 million (2002 — $2.9 million) and incurred administrative expenses and corporate signature rights totaling $6.8 million (2002 — $6.6 million). Canadian Utilities also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million (2002 — $1.2 million). These transactions are in the normal course of business and under normal commercial terms.

18. Employee future benefits

Canadian Utilities maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plans and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plans at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

18. Employee future benefits (continued)

Information about Canadian Utilities' benefit plans, in aggregate, is as follows:

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,195.0**	**$ -**	$1,322.6	$ -
Actual return (loss) on plan assets	**159.1**	**-**	(94.9)	-
Employee contributions	**5.1**	**-**	5.2	-
Benefit payments	**(33.4)**	**-**	(34.2)	-
Payments to defined contribution plans	**(3.3)**	**-**	(3.7)	-
End of year	**$1,322.5**	**$ -**	$1,195.0	$ -
Accrued benefit obligations:				
Beginning of year	**$ 952.0**	**$ 47.9**	$ 884.8	$ 44.8
Current service cost	**20.9**	**1.9**	17.6	1.3
Interest cost	**65.3**	**3.8**	59.4	3.0
Employee contributions	**5.1**	**-**	5.2	-
Benefit payments from plan assets [1]	**(33.4)**	**-**	(34.2)	-
Benefit payments by employer	**(3.6)**	**(1.7)**	(1.6)	(1.8)
Experience losses [2]	**86.3**	**10.6**	20.8	0.6
End of year	**$1,092.6**	**$ 62.5**	$ 952.0	$ 47.9
Funded status:				
Excess (deficiency) of assets over obligations	**$ 229.9**	**$(62.5)**	$ 243.0	$(47.9)
Amounts not yet recognized in financial statements:				
Unrecognized net experience losses	**270.1**	**13.6**	265.4	3.4
Unrecognized net transitional liability (asset)	**(319.0)**	**27.6**	(351.8)	29.9
Accrued asset (liability)	**181.0**	**(21.3)**	156.6	(14.6)
Regulatory asset (liability) [3]	**(128.5)**	**12.6**	(108.6)	8.6
Net accrued asset (liability) recognized (Notes 7, 11)	**$ 52.5**	**$ (8.7)**	$ 48.0	$ (6.0)

(1) Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.

(2) Changes in liability discount rate and long term inflation rate assumptions resulted in experience losses in 2003 of approximately $69.0 million for the pension benefit plans and $2.0 million for the other post employment benefit plans.

(3) The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

18. Employee future benefits (continued)

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan expense (income)				
Components of benefit plan expense (income):				
Current service cost	**$ 20.9**	**$1.9**	$ 17.6	$1.3
Interest cost	**65.3**	**3.8**	59.4	3.0
Expected return on plan assets	**(91.0)**	**-**	(99.5)	-
Amortization of net experience losses	**13.5**	**0.4**	-	-
Amortization of net transitional liability (asset)	**(32.8)**	**2.3**	(30.9)	2.3
Defined benefit plans expense (income)	**(24.1)**	**8.4**	(53.4)	6.6
Defined contribution plans expense	**4.5**	**-**	5.5	-
Total expense (income)	**(19.6)**	**8.4**	(47.9)	6.6
Less: Capitalized	**1.0**	**2.0**	0.6	1.5
Less: Unrecognized defined benefit plans expense (income) [1]	**(19.5)**	**2.5**	(41.3)	1.5
Net expense (income) recognized	**$ (1.1)**	**$3.9**	$ (7.2)	$3.6

[1] The unrecognized defined benefit plans expense (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

Weighted average assumptions

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan expense (income):				
Expected long term rate of return on plan assets for the year	**7.5%**	**-**	8.0%	-
Interest rate for the year	**6.5%**	**6.5%**	6.9%	6.9%
Average compensation increase for the year	**2.75%**	**-**	3.0%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**6.25%**	**6.25%**	6.5%	6.5%
Long term inflation rate	**2.5%**	(1)	2.25%	(1)

[1] The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 10.5% for 2003 grading down over 10 years to 4.5% (2002 – 8.85% for 2002 grading down over 5 years to 4.0%), and, for other medical and dental costs, 4.0% for 2003 and thereafter (2002 – 3.5% for 2002 and thereafter).

18. **Employee future benefits** (continued)

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan expense (income) for 2003 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2003 Pension Benefit Plans		2003 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Expense (Income)	Accrued Benefit Obligation	Benefit Plan Expense (Income)
Expected long term rate of return on plan assets				
1% increase [1]		$(3.5)		
1% decrease [1]		$ 3.5		
Liability discount rate				
1% increase [1]	$(52.2)	$(0.3)	$(2.8)	$(0.3)
1% decrease [1]	$ 52.2	$ 0.3	$ 2.8	$ 0.3
Long term inflation rate [2]				
1% increase [1]	$ 34.6	$ 0.5	$ 2.6	$ 0.5
1% decrease [1]	$(34.6)	$(0.5)	$(2.2)	$(0.4)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans expense (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

Pension benefit plan assets

	2003		2002	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 817.3**	**61.8**	$ 723.6	60.6
Fixed income securities [2]	**442.4**	**33.4**	403.8	33.8
Real estate [3]	**31.1**	**2.4**	36.2	3.0
Cash and other assets [4]	**31.7**	**2.4**	31.4	2.6
	$1,322.5	**100.0**	$1,195.0	100.0

(1) Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2003, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $134.4 million and $148.7 million, respectively (2002 – $137.4 million and $133.7 million, respectively).

(2) Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.

(3) Real estate consists of investments in closed-end real estate funds.

(4) Cash and other assets consist of cash, short term notes and money market funds.

18. Employee future benefits (continued)

At December 31, 2003, plan assets include long term debt of CU Inc. having a market value of \$1.8 million (2002 – \$1.7 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$11.6 million (2002 – \$10.3 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of \$8.7 million (2002 – \$7.8 million).

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. Canadian Utilities is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2002, Canadian Utilities is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2005.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by Canadian Utilities out of general revenues. These supplementary plans had accrued benefit obligations of \$70.9 million at December 31, 2003 (2002 – \$58.7 million).

19. Risk management and financial instruments

Canadian Utilities is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the Logistics and Energy Services segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, Canadian Utilities uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Completion Date	Principal/Face Value	
			2003	2002
6.435%	90 day BA	December 2004	**\$ 2.3**	\$ 3.6
5.147%	90 day BA	December 2007	**51.0**	53.1
5.102%	90 day BA	September 2008	**67.6**	-
7.290%	90 day BA	November 2008	**6.4**	7.7
7.067%	90 day BA	December 2008	**9.0**	10.8
6.461%	90 day BA	June 2011	**4.7**	4.8
7.250%	6 month LIBOR	December 2011	**93.1**	95.6
7.161%	90 day BA	September 2012	**34.3**	35.6
6.825%	Bank Bill Rate in Australia	June 2013	**51.6**	48.9
6.575%	90 day BA	March 2019	**40.7**	9.2
			\$360.7	\$269.3

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees (Note 10).

19. Risk management and financial instruments (continued)

Foreign exchange rate risk

Canadian Utilities has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

Canadian Utilities has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and operational cash flows denominated in EUROs. At December 31, 2003, the contracts consist of purchases of $0.5 million U.S. (2002 — $3.1 million U.S.), and there were no contracts outstanding to sell U.S. dollars (2002 — $0.4 million U.S) or to purchase EUROs (2002 — 4.1 million EUROs).

Energy commodity price risk

As a result of an AEUB approved storage plan related to the Carbon storage facility, Canadian Utilities has entered into certain energy contracts to fix the price of natural gas for the customers of the Utilities segment. All associated costs and benefits of these contracts are passed to customers through regulated rates, and accordingly, Canadian Utilities does not bear any risk for price fluctuations provided that the contracts are in accordance with the storage plan. At December 31, 2003, the contracts consist of natural gas sales of 151 terajoules ("TJ") for $1.0 million (2002 — 3,774.4 TJ for $22.4 million) and natural gas purchases of 151 TJ for $1.0 million (2002 — nil).

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that Canadian Utilities would either pay or receive to settle the contract at December 31.

	2003			2002		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$360.6**	**$(14.0)**	**2004-2019**	$269.8	$(14.0)	2004 - 2019
Foreign exchange forward contracts	**$ 0.7**	**Nil**	**2004**	$ 11.3	$ 1.0	2003

Credit risk

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

20. Commitments and contingencies

Commitments

Canadian Utilities has contractual obligations in the normal course of business, including long term operating leases for office premises and equipment. Future minimum lease payments are as follows:

2004	2005	2006	2007	2008	Total of All Subsequent Years
$12.8	$11.9	$11.2	$10.5	$10.1	$15.1

20. Commitments and contingencies (continued)

Contingencies

Canadian Utilities is party to a number of disputes and lawsuits in the normal course of business. Management is confident that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

21. Regulatory matters

The AEUB issued decisions regarding ATCO Gas', ATCO Electric's and ATCO Pipelines' general rate applications on October 1, 2003, October 2, 2003, and December 2, 2003, respectively. These decisions approved, among other things, for ATCO Electric, a rate of return on common equity of 9.4% and a common equity ratio of 32% for transmission operations and 35% for distribution operations for 2003, for ATCO Gas, a rate of return on common equity of 9.5% and a common equity ratio of 37% for 2003 and 2004 and, for ATCO Pipelines, a rate of return on common equity of 9.5% and a common equity ratio of 43.5% for 2003.

ATCO Electric's and ATCO Pipelines' 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of a generic cost of capital hearing which commenced in November 2003.

The companies, as directed by the AEUB, have refiled the 2003 and 2004 general rate applications incorporating the findings in the decisions. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for ATCO Electric for the 2003 and 2004 test years, accepting the refiling with no material changes. The AEUB has not yet issued its determination of the revenue requirements for ATCO Gas and ATCO Pipelines for the 2003 and 2004 test years following the refilings. It is expected that such determination will not have a material effect on the accounts of Canadian Utilities.

Canadian Utilities has a number of other regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined.

22. Segmented information

Description of segments

Canadian Utilities operates in the following business segments:

The Utilities Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity of Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream and the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, Canadian Utilities owns commercial real estate in Fort McMurray, Alberta.

22. Segmented information (continued)

Segmented results – Three months ended December 31

2003 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies & Other Businesses	Corporate	Intersegment Eliminations	Consolidated
(Unaudited)							
Revenues – external	**$ 632.5** $ 603.3	**$ 171.9** $ 165.8	**$ 142.6** $ 156.9	**$ 3.1** $ 4.5	**$ 0.2** $ 0.2	**$ -** $ -	**$ 950.3** $ 930.7
Revenues – intersegment [1]	**15.3** 23.8	**-** -	**172.9** 107.4	**31.1** 21.5	**2.6** 2.6	**(221.9)** (155.3)	**-** -
Revenues	**$ 647.8** $ 627.1	**$ 171.9** $ 165.8	**$ 315.5** $ 264.3	**$ 34.2** $ 26.0	**$ 2.8** $ 2.8	**$(221.9)** $(155.3)	**$ 950.3** $ 930.7
Earnings attributable to Class A and Class B shares	**$ 36.2** $ 26.8	**$ 35.7** $ 23.4	**$ 14.3** $ 19.4	**$ 5.1** $ 2.8	**$ (4.9)** $ (0.7)	**$ 0.3** $ 1.8	**$ 86.7** $ 73.5

Segmented results – Year ended December 31

2003 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies & Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	**$2,409.8** $1,781.1	**$ 643.4** $ 584.6	**$ 668.6** $ 597.9	**$ 20.6** $ 12.1	**$ 0.2** $ 0.2	**$ -** $ -	**$3,742.6** $2,975.9
Revenues – intersegment [1]	**68.4** 86.1	**-** -	**594.8** 335.8	**106.2** 89.8	**11.2** 10.9	**(780.6)** (522.6)	**-** -
Revenues	**2,478.2** 1,867.2	**643.4** 584.6	**1,263.4** 933.7	**126.8** 101.9	**11.4** 11.1	**(780.6)** (522.6)	**3,742.6** 2,975.9
Operating expenses	**2,084.4** 1,516.7	**351.9** 336.0	**1,119.0** 765.7	**86.2** 74.9	**13.8** 11.8	**(786.6)** (534.6)	**2,868.7** 2,170.5
Depreciation and amortization	**138.6** 126.8	**78.3** 68.2	**41.6** 42.1	**9.9** 7.3	**0.5** 0.4	**-** (0.4)	**268.9** 244.4
Interest expense	**93.6** 96.3	**75.2** 68.4	**22.3** 24.6	**0.8** 0.8	**145.6** 144.1	**(147.2)** (150.1)	**190.3** 184.1
Gain on sale of Viking-Kinsella property	**-** (110.1)	**-** -	**-** -	**-** -	**-** -	**-** -	**-** (110.1)
Interest and other income	**(7.4)** (11.0)	**(7.5)** (8.5)	**(6.9)** (5.1)	**(0.4)** (0.1)	**(158.4)** (151.5)	**147.2** 150.1	**(33.4)** (26.1)
Earnings before income taxes	**169.0** 248.5	**145.5** 120.5	**87.4** 106.4	**30.3** 19.0	**9.9** 6.3	**6.0** 12.4	**448.1** 513.1
Income taxes	**62.6** 92.4	**49.3** 41.8	**24.8** 40.3	**11.2** 7.9	**5.7** 3.2	**2.1** 4.3	**155.7** 189.9
	106.4 156.1	**96.2** 78.7	**62.6** 66.1	**19.1** 11.1	**4.2** 3.1	**3.9** 8.1	**292.4** 323.2
Dividends on equity preferred shares	**8.7** 8.4	**3.5** 3.4	**1.8** 1.7	**-** -	**19.1** 4.7	**-** -	**33.1** 18.2
Earnings attributable to Class A and Class B shares	**$ 97.7** $ 147.7	**$ 92.7** $ 75.3	**$ 60.8** $ 64.4	**$ 19.1** $ 11.1	**$ (14.9)** $ (1.6)	**$ 3.9** $ 8.1	**$ 259.3** $ 305.0
Total assets	**$2,850.0** $2,630.9	**$2,191.0** $2,174.7	**$ 837.9** $ 806.1	**$ 55.2** $ 47.4	**$ 184.8** $ 302.1	**$ (48.4)** $ (26.8)	**$6,070.5** $5,934.4
Purchase of property, plant and equipment	**$ 314.3** $ 274.5	**$ 131.7** $ 236.0	**$ 37.5** $ 48.9	**$ 11.6** $ 10.0	**$ 0.6** $ 0.4	**$ -** $ -	**$ 495.7** $ 569.8

[1] Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

22. Segmented information (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2003	2002	**2003**	2002	**2003**	2002
Revenues	**$3,234.3**	$2,699.4	**$238.3**	$276.5	**$3,742.6**	$2,975.9
Property, plant and equipment	**$4,436.7**	$4,250.0	**$372.7**	$407.0	**$4,809.4**	$4,657.0

23. Sale of Retail operations

In December 2002, Direct Energy Marketing Limited ("Direct Energy") agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric, subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the government of Alberta amending certain natural gas and electricity legislation.

In December 2003, the AEUB issued decisions approving the transfer of the retail operations of ATCO Gas and ATCO Electric to Direct Energy, appointing Direct Energy provider of the natural gas Default Rate Tariff and electricity Regulated Rate Tariff in the ATCO Gas and ATCO Electric service territories and approving the tariff rate structure of Direct Energy Regulated Services, ATCO Gas and ATCO Electric. The City of Calgary has filed leave to appeal the AEUB decision approving the transfer of the retail operations. Canadian Utilities is reviewing the AEUB decisions and certain other conditions which must be satisfied in order to close the sale of its retail business to Direct Energy.

If the sale does close on the anticipated terms, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited comparative interim financial statements for the three months ended December 31, 2003, and the audited comparative financial statements for the year ended December 31, 2003. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

All quarterly information in this document is shaded to differentiate it from the annual information.

The common share capital of the Corporation consists of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

FORWARD-LOOKING INFORMATION

Certain statements contained in this discussion and analysis of financial condition and results of operations constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this discussion and analysis of financial condition and results of operations contains forward-looking statements pertaining to purchase obligations, planned capital expenditures, anticipated completion dates and construction costs of major projects, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, and prevailing economic conditions, as well as other factors, many of which are beyond the control of the Corporation.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from four Business Groups: Utilities, Power Generation, Logistics and Energy Services, and Technologies. For the purposes of financial disclosure, the Technologies Business Group is included in Technologies and Other Businesses and corporate transactions are accounted for as Corporate (see Note 22 to the comparative financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

The Utilities Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream,

and the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, the Corporation owns commercial real estate in Fort McMurray, Alberta.

SELECTED ANNUAL AND QUARTERLY INFORMATION

($ Millions except per share data)

	For the Three Months Ended				Year Ended
	Mar	**Jun**	**Sep**	**Dec**	**Dec 31**
	(unaudited)				
Revenues:					
2003	1,372.2	797.5	622.6	950.3	3,742.6
2002	858.1	644.4	542.7	930.7	2,975.9
2001					3,513.6
Earnings attributable to Class A and Class B shares (1):					
2003	85.8	43.4	43.4	86.7	259.3
2002 (2)	144.2	42.9	44.4	73.5	305.0
2001					237.1
Earnings per Class A and Class B share (1):					
2003	1.35	0.69	0.68	1.37	4.09
2002	2.28	0.67	0.70	1.16	4.81
2001					3.74
Diluted earnings per Class A and Class B share (1):					
2003	1.34	0.69	0.68	1.36	4.07
2002	2.27	0.67	0.70	1.15	4.79
2001					3.72

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *The earnings for the three months ended March 31 and December 31 include earnings of $66.7 million and $0.6 million, respectively, on the sale of the Viking-Kinsella natural gas producing property.*

(3) *Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.*

(4) *The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.*

	Year Ended December 31		
	2003	2002	2001
	($ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (1)	1.26	1.26	1.14
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T (2)	1.26	1.26	1.16
Series U (2)	1.26	1.26	1.16
Series V (3)	1.31	1.17	1.17
Series W (4)	1.44	-	-
Series X (5)	0.93	-	-
Class A and Class B shares	2.04	1.96	1.88
Total assets	6,070.5	5,934.4	5,404.0
Long term debt	1,805.3	1,916.9	1,855.9
Non-recourse long term debt	806.1	821.1	673.8
Equity preferred shares	636.5	486.5	336.5
Class A and Class B share owners' equity	1,951.6	1,830.1	1,643.8

Notes:

(1) The dividend was reset to $1.26 (5.05%) for the period between December 1, 2001 and December 1, 2006.
(2) The dividend was reset to $1.26 (5.05%) for the period between December 2, 2001 and December 2, 2006.
(3) The dividend was reset to $1.31 (5.25%) for the period between October 3, 2002 and October 3, 2007.
(4) Issued December 3, 2002.
(5) Issued April 17, 2003.
(6) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

The principal factors that have caused variations in quarterly revenues have been fluctuations in temperatures, changes in natural gas and electricity prices and the timing of rate decisions. In the case of earnings, the principal factors have been the sale of the Viking-Kinsella natural gas producing property (the "Viking property") in the first quarter of 2002, changes in electricity prices in Alberta, fluctuations in temperatures and the timing of rate decisions.

RESULTS OF OPERATIONS

Consolidated Operations

Revenues for the three months ended December 31, 2003, increased by $19.6 million to $950.3 million, primarily due to the higher price of natural gas purchased for customers on a "no-margin" basis, colder temperatures. the impact of the Alberta Energy and Utilities Board ("AEUB") decision respecting the 2003/2004 general rate application of ATCO Gas (the "2003/2004 rate decision for ATCO Gas"), and increased business activity in the Power Generation Business Group and ATCO Midstream, partially offset by the impact of the AEUB decision respecting the 2003/2004 general tariff application of ATCO Electric (the "2003/2004 rate decision for ATCO Electric"), the impact of the AEUB decision respecting the 2003/2004 general rate application of ATCO Pipelines (the "2003/2004 rate decision for ATCO Pipelines") and lower revenues from ATCO Frontec projects. Temperatures for the three months ended December 31, 2003, were 3.2% warmer than normal, compared to 11.4% warmer than normal for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $766.7 million to $3,742.6 million, primarily due to the higher price of natural gas and electricity purchased for customers on a "no-margin" basis by ATCO Gas and ATCO Electric, higher natural gas prices on gas sales by ATCO Midstream, and increased business activity in all subsidiaries except ATCO Pipelines and ATCO Frontec. The impact of warmer temperatures in ATCO Gas,

reduced earnings from the Barking generating plant in the United Kingdom, and the impact of the 2003/2004 rate decision for ATCO Pipelines partially offset the increased revenues. Temperatures in 2003 were 3.4% colder than normal, whereas temperatures in 2002 were 6.3% colder than normal.

Earnings attributable to Class A shares and Class B shares for the three months ended December 31, 2003, increased by $13.2 million ($0.21 per share) to $86.7 million ($1.37 per share), primarily due to the impact of the 2003/2004 rate decision for ATCO Gas, stronger operational results in Alberta Power (2000) and the Technologies Business Group, colder temperatures in ATCO Gas and a favourable tax adjustment in Australia for ATCO Power ($8.9 million), partially offset by the impact of the 2003/2004 rate decisions for ATCO Pipelines and ATCO Electric, and the carrying costs, net of investment income, in respect of the $400.0 million of preferred shares and debentures issued between November 2002 and April 2003 that reduced earnings by $3.5 million.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2003, increased by $21.6 million ($0.34 per share) to $259.3 million ($4.09 per share), excluding the impact of the sale of the Viking property. Earnings for 2002 were $237.7 million, excluding the after-tax gain of $67.3 million on the sale of the Viking property. 2002 earnings in total were $305 million.

This increase was primarily due to stronger operational results in all subsidiaries except ATCO Pipelines and ATCO Frontec, and a favourable tax adjustment in Australia for ATCO Power ($8.9 million). These increases more than offset the carrying costs, net of investment income, in respect of the $400.0 million of preferred shares and debentures issued between November 2002 and April 2003 that reduced earnings by $13.0 million in 2003. These preferred shares and debentures were issued during a low interest rate environment to strengthen the Corporation's balance sheet and allow for future growth.

Return on common equity was 13.7% in 2003.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2003, increased by $10.8 million to $714.7 million, largely due to higher natural gas supply costs and higher selling and administrative expenses associated with the impact of the 2003/2004 rate decision for ATCO Gas, increased bad debts expense in ATCO Gas and higher share appreciation rights expense, partially offset by lower purchased power costs.

Operating expenses for the year ended December 31, 2003, increased by $698.2 million to $2,868.7 million, primarily due to higher natural gas and purchased power costs and higher operation and maintenance expenses associated with increased business activity in all subsidiaries except ATCO Pipelines and ATCO Frontec.

Depreciation and amortization expenses for the three months ended December 31, 2003, increased by $4.8 million to $72.7 million, primarily due to capital additions in 2003 and 2002.

Depreciation and amortization expenses for the year ended December 31, 2003, increased by $24.5 million to $268.9 million, primarily due to capital additions in 2003 and 2002, partially offset by depreciation adjustments associated with the sale of the Viking property in 2002.

Interest expense for the three months ended December 31, 2003, increased by $1.8 million to $47.1 million, primarily due to interest on non-recourse financings for the new Cory, Muskeg River, Oldman River and Scotford generating plants commissioned by ATCO Power in 2003 (the "New ATCO Power Generating Plants").

Interest expense for the year ended December 31, 2003, increased by $6.2 million to $190.3 million, primarily due to interest on non-recourse financing for the New ATCO Power Generating Plants, partially offset by lower interest rates associated with higher cost long term debt refinanced in 2002 and 2003. Interest capitalized on non-regulated projects for the year ended December 31, 2003, decreased by $4.6 million to $18.2 million.

In 2002, the Corporation sold its Viking property, which had a net book value of approximately $40 million, for $550 million. In accordance with an AEUB decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments. The Corporation's share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million before income taxes of $42.8 million. This sale increased earnings by $67.3 million.

Interest and other income for the three months ended December 31, 2003, increased by $1.7 million to $9.5 million, primarily due to interest income on higher cash balances.

Interest and other income for the year ended December 31, 2003, increased by $7.3 million to $33.4 million, primarily due to interest income on higher cash balances.

Income taxes for the three months ended December 31, 2003, decreased by $14.6 million to $29.7 million, largely due to lower income tax rates, ATCO Power's favourable tax adjustment in Australia and a change in income tax methodology arising from the 2003/2004 rate decision for ATCO Pipelines, partially offset by higher earnings.

Income taxes for the year ended December 31, 2003, excluding the $42.8 million of income taxes on the sale of the Viking property in 2002, increased by $8.6 million to $155.7 million. This increase was primarily due to higher earnings and the impact of a 2002 refund to customers of amounts previously recovered from customers for future income taxes related to the Viking property. This increase was partially offset by lower income tax rates, ATCO Power's favourable tax adjustment in Australia, and a change in income tax methodology arising from the 2003/2004 rate decision for ATCO Pipelines. Income taxes for 2002, including the impact of the sale of the Viking property, were $189.9 million.

Dividends on equity preferred shares for the three months increased by $3.7 million to $8.9 million, primarily due to the issue of $150.0 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W ("Series W Preferred Shares") on December 3, 2002, and $150.0 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X ("Series X Preferred Shares") on April 17, 2003.

Dividends on equity preferred shares for the year ended December 31, 2003, increased by $14.9 million to $33.1 million, primarily due to the issue of the Series W Preferred Shares and the Series X Preferred Shares.

Segmented revenues for the three months and for the year ended December 31, 2003, were as follows:

Business Groups	**Three Months Ended December 31**		**Year Ended December 31**	
($ Millions)	**2003**	2002	**2003**	2002
	(unaudited)			
Utilities	**647.8**	627.1	**2,478.2**	1,867.2
Power Generation	**171.9**	165.8	**643.4**	584.6
Logistics and Energy Services	**315.5**	264.3	**1,263.4**	933.7
Technologies and Other Businesses	**34.2**	26.0	**126.8**	101.9
Corporate	**2.8**	2.8	**11.4**	11.1
Intersegment eliminations	**(221.9)**	(155.3)	**(780.6)**	(522.6)
Total	**950.3**	930.7	**3,742.6**	2,975.9

Segmented earnings attributable to Class A and Class B shares for the three months and for the year ended December 31, 2003, were as follows:

Business Groups	**Three Months Ended December 31**		**Year Ended December 31**	
($ Millions)	**2003**	2002	**2003**	2002
	(unaudited)			
Utilities (1)	**36.2**	26.8	**97.7**	147.7
Power Generation	**35.7**	23.4	**92.7**	75.3
Logistics and Energy Services	**14.3**	19.4	**60.8**	64.4
Technologies and Other Businesses	**5.1**	2.8	**19.1**	11.1
Corporate	**(4.9)**	(0.7)	**(14.9)**	(1.6)
Intersegment eliminations	**0.3**	1.8	**3.9**	8.1
Total	**86.7**	73.5	**259.3**	305.0

Note:

(1) *The earnings for the three months ended December 31, 2002, and for the year ended December 31, 2002, include earnings of $0.6 million and $67.3 million, respectively, on the sale of the Viking property.*

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2003, increased by $20.7 million to $647.8 million, primarily due to higher revenues in ATCO Gas, resulting from higher prices of natural gas purchased for customers on a "no-margin" basis, colder temperatures, the impact of the 2003/2004 rate decision for ATCO Gas and customer additions. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric. Temperatures for the three months ended December 31, 2003, were 3.2% warmer than normal, compared to 11.4% warmer than normal for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $611.0 million to $2,478.2 million, primarily due to higher revenues in ATCO Gas, resulting from higher prices for natural gas purchased for customers on a "no-margin" basis, higher sales and the impact of the 2003/2004 rate decision for ATCO Gas, and higher prices for electricity purchased for customers on a "no-margin" basis in ATCO Electric. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric and the impact of warmer temperatures in ATCO Gas. Temperatures in 2003 were 3.4% colder than normal, whereas temperatures in 2002 were 6.3% colder than normal.

Earnings for the three months ended December 31, 2003, increased by $9.4 million to $36.2 million, primarily the result of improved operating results in ATCO Electric, stronger performance in ATCO Gas as a result of the impact of the 2003/2004 rate decision for ATCO Gas, colder temperatures and customer additions, and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon natural gas storage facility. This increase was partially offset by higher operation and maintenance costs, and the impact of the 2003/2004 rate decision for ATCO Electric.

Earnings for the year ended December 31, 2003, increased by $17.3 million to $97.7 million, excluding the $67.3 million in earnings on the sale of the Viking property in 2002. This increase was primarily the result of improved operating results and growth in ATCO Electric, stronger performance in ATCO Gas as a result of the impact of the 2003/2004 rate decision for ATCO Gas and customer additions, and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon natural gas storage facility. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric, higher operating costs, and the impact of warmer temperatures in ATCO Gas. Earnings for 2002, including the impact of the sale of the Viking property, were $147.7 million. The $97.7 million of earnings amounted to 37.7% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, increased by $567.7 million to $2,084.4 million, primarily due to higher natural gas supply and purchased power costs. Natural gas supply and purchased power costs are recovered in customer rates. Natural gas supply costs are based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers and revenues and natural gas supply costs are adjusted accordingly.

Purchased power costs are based on the actual cost of electricity purchased, whereas the amount included in customer rates is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers. As a consequence, changes in natural gas supply and purchased power costs have no effect on the Corporation's earnings. ATCO Gas' customers have been billed on a monthly flow-through basis since April 1, 2002. ATCO Electric's customers have been billed on a monthly flow-through of market prices for electric energy since April 1, 2003. The "flow-through" rate is based on the actual spot market price for the energy that customers use during each billing period.

In the first quarter of 2003, ATCO Gas commenced the first phase of a $278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The 2003/2004 rate decision for ATCO Gas approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program. The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

Included in ATCO Gas' deferred gas account balance is an amount representing the difference between the amount of natural gas "transportation" customers put onto ATCO Gas' and ATCO Pipelines' pipeline systems and the amount of natural gas these same customers remove from the system. This amount is referred to as a "transportation imbalance". In addition, the deferred gas cost account includes an amount representing the difference between all purchases of natural gas and sales of natural gas to ATCO Gas customers.

The AEUB has approved the inclusion of the transportation imbalances in the deferred gas account. Adjustments arising out of a monthly reconciliation of this account are collected from or reimbursed to customers.

ATCO Gas and ATCO Pipelines have been working together to confirm the accuracy of the historical transportation imbalances. It is anticipated that this process will be completed during the first quarter of 2004, at which time an application may be made to the AEUB to address any required adjustments to the deferred gas cost account.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2003, increased by $6.1 million to $171.9 million, primarily due to the commissioning of the New ATCO Power Generating Plants and higher capacity and energy charges and improved operating results in Alberta Power (2000). Prices for electricity sold to the Alberta Electric System Operator ("AESO"), formerly the Alberta Power Pool, for the three months ended December 31, 2003, averaged $54.71, compared to average prices of $61.58 for the corresponding period in 2002. Natural gas prices for the three months ended December 31, 2003, averaged $5.50 per gigajoule, compared to average prices of $5.37 for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $58.8 million to $643.4 million, primarily due to higher prices received for electricity sold to the AESO, the commissioning of the New ATCO Power Generating Plants, and higher capacity and energy charges and improved operating results in Alberta Power (2000). These increases were partially offset by reduced revenues from the Barking generating plant in the United Kingdom, due to the loss in late 2002 of the long term offtake agreement with TXU Europe (described below), resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements. AESO prices averaged $62.99 per megawatt hour in 2003, compared to average prices of $43.94 in 2002. Natural gas prices averaged $6.31 per gigajoule in 2003, compared to average prices of $3.84 in 2002.

Earnings for the three months ended December 31, 2003, increased by $12.3 million to $35.7 million, primarily due to a favourable tax adjustment in Australia, and the commencement in 2003 of the amortization of deferred availability incentives.

Earnings for the year ended December 31, 2003, increased by $17.4 million to $92.7 million, primarily due to higher prices received for electricity sold to the AESO, a favourable tax adjustment in Australia, improved operating results in ATCO Power's Australian generating plants, the commencement in 2003 of the amortization of deferred availability incentives and improved operating results in Alberta Power (2000). This increase was partially offset by higher fuel costs arising from higher natural gas prices and reduced earnings from the Barking generating plant in the United Kingdom, due to the loss in late 2002 of the long term offtake agreement with TXU Europe (described

below), resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements. The $92.7 million of earnings amounted to 35.8% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, increased by $15.9 million to $351.9 million, primarily the result of the commissioning of the New ATCO Power Generating Plants and higher natural gas fuel costs in Alberta.

ATCO Power completed construction of the New ATCO Power Generating Plants in 2003 for a total cost of approximately $745 million, of which ATCO Power's share was approximately $430 million. These costs were approximately 13% above original cost estimates, primarily due to labour and engineering markets in Alberta, which tightened during construction, and increased equipment, financing and foreign exchange costs. A portion of the additional costs will be recoverable over the term of the commercial contracts.

On November 19, 2002, an administration order was issued by a United Kingdom court for TXU Europe, which had a long term offtake agreement for 27.5% of the power produced by the Barking power plant, a 1,000 megawatt plant in London, England, in which the Corporation, through Barking Power Limited, has a 25.5% equity interest. An administration order is similar to a Chapter 11 bankruptcy filing in the United States. Barking Power Limited has filed a claim with the Administrator and is working with the Administrator and Creditors' Committees on liquidation of TXU Europe and settlement of claims. The Barking power plant will continue to supply 725 megawatts of power under long term contracts. The 275 megawatts of power previously supplied to TXU Europe is being sold under short term bilateral agreements.

At December 31, 2003, all of ATCO Power's non-regulated independent cogeneration and generating plants were in service, with the exception of the Brighton Beach project which is under construction.

A partnership formed by ATCO Power and Ontario Power Generation ("OPG") is constructing and will operate the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant at the site of the former J.C. Keith Generating Station, near Windsor, Ontario. Coral Energy Canada Inc. has agreed to supply and pay for the natural gas to be used at the plant and will own, market and trade all the electricity produced. Construction is progressing with commercial operation scheduled for the summer of 2004. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and OPG owns 50%. The estimated costs to complete the generating plant have increased from original estimates by approximately 19% to $562 million due to higher supply and assembly costs for the heat recovery steam generator, higher costs for civil works and changes in engineering scope. In addition, ATCO Power has provided a contingency of $10 million for unforeseen commissioning costs. ATCO Power's share of the total estimated cost is $230 million.

On September 8, 2003, SaskPower International Inc. announced that it had selected ATCO Power as its joint venture partner to potentially develop up to 150 megawatts of wind generation power in Saskatchewan.

In 2001, Alberta Power (2000) and the Alberta Balancing Pool entered into an agreement which gave the Alberta Balancing Pool control of the 150 megawatt, coal-fired H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the generating plant and coal inventory. Alberta Power (2000) operated the generating plant under a cost of service contract with the Alberta Balancing Pool. On August 6, 2003, the Alberta Balancing Pool announced that it had entered into an agreement for the sale of plant. Alberta Power (2000) extended its cost of service contract until January 29, 2004, when the plant was sold by the Alberta Balancing Pool to a third party. As part of the sale, Alberta Power (2000) was relieved of all decommissioning risk, including any environmental liabilities incurred while Alberta Power (2000) was operating the generating plant.

Logistics and Energy Services

Revenues from the Logistics and Energy Services Business Group for the three months ended December 31, 2003, increased by $51.2 million to $315.5 million, primarily due to higher prices for natural gas purchased for ATCO Midstream's customers and higher natural gas liquids prices, partially offset by the impact of the 2003/2004 rate decision for ATCO Pipelines, and reduced business activity in ATCO Frontec, primarily resulting from the expiry of a contract in September 2003 with the Department of National Defence to provide support services for six peace-keeping installations in Bosnia-Herzegovina (the "Balkans contract").

Revenues for the year ended December 31, 2003, increased by $329.7 million to $1,263.4 million, largely due to higher natural gas liquids prices and higher prices for natural gas purchased for ATCO Midstream's customers, partially offset by the impact of the 2003/2004 rate decision for ATCO Pipelines and lower revenues from ATCO Frontec projects, primarily reflecting the expiry of the Balkans contract.

Earnings for the three months ended December 31, 2003, decreased by $5.1 million to $14.3 million, primarily due to the impact of the 2003/2004 rate decision for ATCO Pipelines, and lower earnings from gas gathering and processing and storage operations in ATCO Midstream, partially offset by higher earnings from natural gas liquids in ATCO Midstream.

Earnings for the year ended December 31, 2003, decreased by $3.6 million to $60.8 million, primarily due to the impact of the 2003/2004 rate decision for ATCO Pipelines and lower earnings from ATCO Frontec projects and ATCO Midstream's storage operations, partially offset by higher earnings from ATCO Midstream's natural gas liquids operations. The $60.8 million of earnings amounted to 23.4% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, net of intersegment expenses, increased by $105.6 million, primarily due to higher natural gas prices on gas sales by ATCO Midstream and higher shrinkage gas and power costs in ATCO Midstream.

Technologies and Other Businesses

Revenues from Technologies and Other Businesses for the three months ended December 31, 2003, increased by $8.2 million to $34.2 million, primarily due to increased business activity and commencement of work for new customers.

Revenues for the year ended December 31, 2003, increased by $24.9 million to $126.8 million, largely due to increased business activity and commencement of work for new customers.

Earnings for the three months ended December 31, 2003, increased by $2.3 million to $5.1 million, primarily due to increased business activity and cost containment initiatives.

Earnings for the year ended December 31, 2003, increased by $8.0 million to $19.1 million, largely due to increased business activity and cost containment initiatives. The $19.1 million of earnings amounted to 7.4% of consolidated earnings of the Corporation.

ATCO I-Tek Business Services Ltd. has entered into a 10-year contract with Direct Energy Marketing Limited ("Direct Energy") to provide billing and customer care services to nearly one million Alberta customers. Commencement of the contract is conditional upon the closing of the sale of ATCO Gas' and ATCO Electric's retail operations to Direct Energy (see "Business Risks – Regulated Operations – Sale of Retail Operations").

Corporate

Earnings for the three months ended December 31, 2003, decreased by $4.2 million to $(4.9) million, primarily due to higher interest expense and preferred share dividends resulting from the issue of $100.0 million of 6.14% Debentures in November 2002 and the Series W and Series X Preferred Shares, net of investment income.

Earnings for the year ended December 31, 2003, decreased by $13.3 million to $(14.9) million, primarily due to higher interest expense and preferred share dividends resulting from the issue of $100.0 million of 6.14% Debentures in November 2002 and the Series W and Series X Preferred Shares, net of investment income.

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. Management did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities. During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. However, the Federal Government has commenced an appeal of the Tax Court's decision with the Federal Court of Appeal. Consequently, the future income tax reduction of $12.9 million has not been adjusted.

REGULATORY MATTERS

Regulated operations are conducted by ATCO Electric, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., CU Water, and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

In August 2002, the Government of Alberta announced changes to utility legislation designed to improve the environment for retail competition in the Province. Amendments to the Electric Utilities Act and Gas Utilities Act received Royal Assent in March 2003 and were proclaimed in force in June 2003. These changes were designed to bring customer choice for both gas and electricity into closer alignment, as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities. In July 2003, ATCO Gas filed its compliance application in accordance with the new legislation.

In December 2003, the AEUB issued a decision approving the implementation of the "One Bill Model" no later than April 1, 2004. The One Bill Model will ensure that customers who choose to purchase their natural gas requirements from a retailer will receive only one bill for natural gas service. Previously, customers would receive a bill from the retailer for the purchase of the commodity and a separate bill from ATCO Gas for the delivery service.

In April 2003, the AEUB determined that it would proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to determine the rate of return on equity and capital structure for all utilities under the jurisdiction of the AEUB. Hearings were completed in January 2004. A decision from the AEUB is not expected until the third quarter of 2004.

In May 2003, the AEUB issued a decision respecting affiliate transactions between ATCO Electric, ATCO Gas and ATCO Pipelines (the "ATCO utilities") and their affiliates. The decision and the resulting Code of Conduct set the framework for ongoing affiliate transactions. The ATCO utilities must be able to demonstrate that services or products from an affiliate have been acquired at a price that is no more than the fair market value of such services or products.

ATCO Electric

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers, and permitting ATCO Electric to sell these deferred costs and related rights. In 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. Generally accepted accounting principles required that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received resulted in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bore interest at 3.3975%, which approximated the interest earned on the deferred costs. The obligation principal and interest incurred were paid to the purchaser as the deferred costs and interest earned were collected from customers. At December 31, 2003, the outstanding obligation was nil.

In June 2003, the AEUB issued a decision approving the collection from customers of interim balances as applied for by ATCO Electric of $4.8 million for the 2002 regulated rate option deferral accounts and $16.6 million for the 2003 regulated rate option energy deferral account accumulated for the first 3 months of 2003. The AEUB directed that ATCO Electric collect these interim balances from customers over the period July 1, 2003, to December 31, 2003.

In August 2002, ATCO Electric filed a general tariff application with the AEUB for the 2003, 2004 and 2005 test years. In a decision dated December 11, 2002, the AEUB approved interim rates effective January 1, 2003. Hearings for ATCO Electric's general tariff application for the 2003, 2004 and 2005 test years commenced on April 15, 2003, and were completed in May 2003. During the hearings, ATCO Electric withdrew the 2005 test year from its application in light of uncertainty around whether the equity component and return for 2005 would be determined based on the merits of its application or through the generic cost of capital proceeding.

In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. However, the 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of the generic cost of capital hearing. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Electric, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes.

In September 2003, ATCO Electric received approval from the AEUB to build a $95.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake. The line includes three substations and is expected to be completed by August 31, 2004.

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

ATCO Gas

In August 2002, ATCO Gas filed a general rate application with the AEUB for the 2003 and 2004 test years. In December 2002, the AEUB issued a decision approving rates on an interim basis effective January 1, 2003. In a decision dated October 1, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37%. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Gas, as directed by the AEUB, has refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements for the 2003 and 2004 test years.

In February 2003, the AEUB issued a decision approving the methodology of distributing the proceeds from the sale of the Beaverhill Lake and Fort Saskatchewan natural gas producing properties, and in March 2003, $23 million of the related sales proceeds was refunded to ATCO Gas' North division customers. The sale has no significant impact on earnings.

In March, 2003, $2.5 million was refunded to ATCO Gas' North division customers. This resulted from the AEUB approval of the final 2002 distribution service rates for ATCO Gas' North division, as established in a negotiated settlement.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties located in the City of Calgary, known as the Calgary Stores Block, for $6.6 million and subsequently issued a decision allocating $4.1 million of the proceeds to customers. Leave to appeal this decision was granted on July 12, 2002. On January 27, 2004, the Alberta Court of Appeal issued a decision which overturned the AEUB decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas. ATCO Gas has not recorded the impact of the appeal decision to date as the period to appeal the court's decision has not yet expired.

ATCO Pipelines

In January 2003, the AEUB issued a decision approving ATCO Pipelines' negotiated settlement of the 2001/2002 exchange deferred account deficit, which arose from the exchange mechanism utilized to deliver net producer transportation quantities sourced from the ATCO system onto the system owned by NOVA Gas Transmission Ltd. The decision approved mechanisms to collect ATCO Pipelines' South division deficit of approximately $9.0 million over a two year period. It further allowed the collection of ATCO Pipelines' North division deficit of $2.3 million

in 2003. Approximately $3.5 million remains to be collected in 2004. The decision also provided for the recovery of carrying costs.

In February 2003, ATCO Pipelines filed a general rate application for the 2003 and 2004 test years. In a decision dated December 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. The rate of return on common equity and the common equity ratio for 2004 will be determined as part of the generic cost of capital hearing. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Pipelines, as directed by the AEUB, has refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements for the 2003 and 2004 test years.

In October 2003, ATCO Pipelines filed a 2004 Phase II general rate application for new rates. This application is part of a broader process through which the AEUB will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations for the three months ended December 31, 2003, decreased by $18.2 million to $153.3 million, primarily the result of higher current income taxes resulting from timing differences in the recognition of revenues and expenses for tax reporting purposes and decreased deferred availability incentives in Alberta Power (2000), partially offset by stronger earnings.

Cash flow from operations for the year ended December 31, 2003, increased by $21.2 million to $525.8 million, primarily due to stronger earnings, partially offset by higher current income taxes resulting from timing differences in the recognition of revenues and expenses for tax reporting purposes and decreased deferred availability incentives in Alberta Power (2000). In addition, in the first quarter of 2002, ATCO Gas refunded to customers a total of $405.6 million related to the sale of the Viking property, of which $20.6 million reduced cash flow from operations.

Investing for the three months ended December 31, 2003, decreased by $21.3 million to $125.0 million, primarily due to the collection of non-current deferred electricity costs and changes in non-cash working capital in respect of investing activities, partially offset by higher capital expenditures. Capital expenditures for the three months ended December 31, 2003, increased by $21.6 million to $176.7 million, primarily due to increased investment in regulated electric transmission and natural gas distribution projects, partially offset by lower investment in non-regulated power generation projects.

Investing for the year ended December 31, 2003, excluding the $107.7 million sale of the Viking property in 2002, decreased by $93.0 million to $434.0 million, primarily due to lower capital expenditures and increased proceeds on disposal of other property, plant and equipment, partially offset by changes in non-cash working capital in respect of investing activities. Investing for 2002, including the impact of the sale of the Viking property, was $419.3 million. Capital expenditures for 2003 decreased by $74.1 million to $495.7 million, primarily due to lower investment in non-regulated power generation projects and in regulated natural gas transmission projects, partially offset by increased investment in regulated natural gas distribution and regulated electric generation projects.

During the three months ended December 31, 2003, the Corporation redeemed $42.0 million of notes payable, issued $12.0 million of long term debt and redeemed $66.8 million of long term debt and $5.5 million of non-recourse long term debt, resulting in a net debt reduction of $102.3 million.

During the year ended December 31, 2003, the Corporation issued $25.5 million of long term debt and $40.7 million of non-recourse long term debt for the Brighton Beach project, and redeemed $60.0 million of 7.25% debentures, $79.1 million of other long term debt and $38.0 million of non-recourse long term debt, resulting in a net debt reduction of $110.9 million.

A planned issue of $180.0 million of debentures by CU Inc. in 2003 was deferred until January 2004 pending clarification of one of the Corporation's credit ratings (see "Credit Ratings"). As a result of the uncertainty surrounding the timing of the receipt of the credit rating, the Corporation utilized its cash resources in late 2003 to temporarily pay down outstanding debt. These payments amounted to approximately $210 million, of which approximately $150 million was advanced to ATCO Gas and ATCO Electric, and approximately $60 million to other subsidiaries of the Corporation. In January 2004, the amounts advanced to ATCO Gas and ATCO Electric were repaid from the proceeds of the CU Inc. $180.0 million issue of 5.432% Debentures and the remaining amounts were replaced with bank borrowings.

During 2003, the opening balance of the deferred electricity cost obligation was reduced by $51.0 million, which represents the amount of the deferred electricity cost obligation collected and remitted during the period January 1, 2003, to December 31, 2003. The deferred electricity cost obligation has now been fully repaid.

In April 2003, the Corporation issued 6,000,000 Series X Preferred Shares, having a dividend rate of 6.00%, at a price of $25.00 per share, for aggregate gross proceeds of $150.0 million. The net proceeds of the issue were added to the general funds of the Corporation to be used for general corporate purposes including capital expenditures.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $550 million in 2004. Included in these capital expenditures are committed amounts relating to ATCO Electric's 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake, ATCO Power's Brighton Beach project, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario and a project to improve operating efficiency at Alberta Power (2000)'s Sheerness and Battle River generating plants. ATCO Electric's transmission line and the Brighton Beach project are currently under construction. These three projects are expected to be completed in 2004, at a cost of approximately $100 million. The remainder of the 2004 capital expenditures, amounting to approximately $450 million, is uncommitted and relates primarily to regulated operations.

Contractual obligations for the next five years and thereafter are as follows:

Contractual Obligations	Total	Payments Due by Period Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
			($ Millions)		
Long term debt	1,805.3	113.8	304.5	162.0	1,225.0
Non-recourse long term debt	852.4	46.3	118.5	136.9	550.7
Operating leases	71.6	12.8	23.1	20.6	15.1
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	1,115.5	115.5	228.4	222.0	549.6
Alberta Power (2000) coal purchase contracts (2)	874.7	42.0	86.6	91.1	655.0
Alberta Power (2000) capital expenditures (3)	9.9	9.9	-	-	-
ATCO Power natural gas fuel supply contracts (4)	457.3	59.9	122.7	117.9	156.8
ATCO Power operating and maintenance agreements (5)	103.9	16.6	25.0	27.3	35.0
ATCO Power capital expenditures (6)	23.8	22.9	0.6	0.3	-
Other	21.5	20.5	1.0	-	-
Total	5,335.9	460.2	910.4	778.1	3,187.2

Notes:

(1) ATCO Gas has obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2003, and assumes a remaining life of 10 years for the gas reserves. The cost of natural gas purchased under these obligations is recoverable from ATCO Gas' customers. These purchase obligations would transfer to Direct Energy upon the sale of the retail energy business of ATCO Gas.

(2) Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.

(3) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.

(4) ATCO Power has various contracts to purchase natural gas for its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 82% of these costs. The balance of 18% is currently being recovered under short term bilateral agreements.

(5) ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.

(6) ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At December 31, 2003, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
		($ Millions)	
Long term committed	350.0	16.2	333.8
Short term committed	624.3	49.8	574.5
Uncommitted	178.5	14.1	164.4
Total	1,152.8	80.1	1,072.7

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

Current and long term future income tax liabilities of $238.5 million at December 31, 2003, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2002, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The offer expired on May 19, 2003. Over the life of the offer, 17,300 shares were purchased, all of which were purchased in 2003. On May 20, 2003, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The offer will expire on May 19, 2004. From May 20, 2003, to February 6, 2004, 56,600 shares have been purchased, all of which were purchased in 2003.

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B shares. In 2003, the Corporation increased the dividends on Class A and Class B shares by $0.08 per share, the same increase as in 2002. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2004, the quarterly dividend payment has been increased by $0.02 to $0.53 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

Credit Ratings

The current ratings on the Corporation's and CU Inc.'s securities are as follows:

	DBRS (1)	**S&P (2)**
Canadian Utilities Limited:		
Debentures	A	A-
Commercial paper	R-1 (low)	A-1 (mid)
Preferred shares:		
Obligations of CU Inc. (3)	Pfd-2 (high)	P-2 (high)
Obligations of CU	Pfd-2	P-2 (high)
CU Inc.:		
Debentures	A (high)	A
Commercial paper	R-1 (low)	A-1 (mid)
Preferred shares	Pfd-2 (high)	Not rated

Notes:

(1) *Dominion Bond Rating Service Limited ("DBRS") maintains a stable trend on the above securities.*

(2) *In January 2004, Standard and Poor's ("S&P") announced it had lowered its ratings on the Corporation's debentures and preferred shares from A to A- and from P-1 (low) to P2 (high), respectively, and CU Inc.'s debentures from A+ to A. At the same time, the ratings were removed from CreditWatch, where they were placed March 5, 2003. The outlook is stable.*

(3) *Refers to the Cumulative Redeemable Second Preferred Shares Series Q, R and S and the Perpetual Cumulative Second Preferred Shares Series U and V which were issued by Canadian Utilities Limited prior to the creation of CU Inc. on March 12, 1999.*

On January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of $750.0 million of debentures over the twenty-five month life of the prospectus. On January 23, 2004, CU Inc. issued $180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

DISCLOSURE OF OUTSTANDING SHARE DATA

At February 25, 2004, the Corporation had outstanding 41,165,891 Class A shares and 22,247,494 Class B shares.

The owners of the Class A shares and the Class B shares are entitled to share equally, on a share-for-share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B shares are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares, which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A shares is set out in a Certificate of Amendment dated September 10, 1982 issued to the Corporation pursuant to the Canada Business Corporations Act.

TRANSACTIONS WITH RELATED PARTIES

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.8 million, recovered administrative expenses and business development costs totaling $3.0 million, and incurred administrative expenses and corporate signature rights totaling $6.8 million. The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million. These transactions are in the normal course of business and under normal commercial terms.

BUSINESS RISKS

During 2002, the Government of Canada ratified the Kyoto Protocol. The Corporation is unable to determine what impact, if any, the ratification will have on its operations as the implementation plan has not yet been released by the Government. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

Regulated Operations

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the

implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

Based on customer requirements in 2003, ATCO Electric estimates that this new policy will require it to purchase approximately 2,000 gigawatt hours (approximately $100 million based on current prices) of electricity per year on a fixed price basis. ATCO Electric will attempt to minimize the credit risk and price risk for volume variances associated with buying electricity in the forward market at fixed prices and then selling to customers at fixed rates by entering into appropriate hedging strategies, adopting prudent credit policies and negotiating with customers a risk premium, a hedging framework and a pricing mechanism involving frequent load forecast updates and rate adjustments. There can be no guarantee that ATCO Electric will be able to recover all of the costs associated with this new energy purchasing policy.

Sale of Retail Operations

In December 2002, Direct Energy agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric, subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the government of Alberta amending certain natural gas and electricity legislation. In December 2003, the AEUB issued decisions approving the transfer of the retail operations of ATCO Gas and ATCO Electric to Direct Energy, appointing Direct Energy provider of the natural gas Default Rate Tariff and electricity Regulated Rate Tariff in the ATCO Gas and ATCO Electric service territories and approving the tariff rate structure of Direct Energy Regulated Services, ATCO Gas and ATCO Electric. The City of Calgary has filed leave to appeal the AEUB decision approving the transfer of the retail operations. The Corporation is reviewing the AEUB decisions and certain other conditions which must be satisfied in order to close the sale of its retail business to Direct Energy.

If the sale does close on the anticipated terms, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

Alberta Power (2000)

Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's were based.

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's.

Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

At December 31, 2003, the Corporation had recorded $43.3 million of deferred availability incentives.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

As a result of unprecedented drought conditions, the water level in the cooling pond used by the Battle River plant in its production of electricity had fallen to an all-time low in early 2003, and the Corporation made a force majeure claim in respect of short term curtailed plant production which was experienced during the first quarter of 2003. Water levels continue to be below normal levels, however sufficient water is currently available to permit the plant to produce electricity according to its PPA contractual requirements. The Corporation is preparing submissions for the arbitration hearings scheduled to commence May 3, 2004, in respect of the force majeure claim.

Non-Regulated Operations

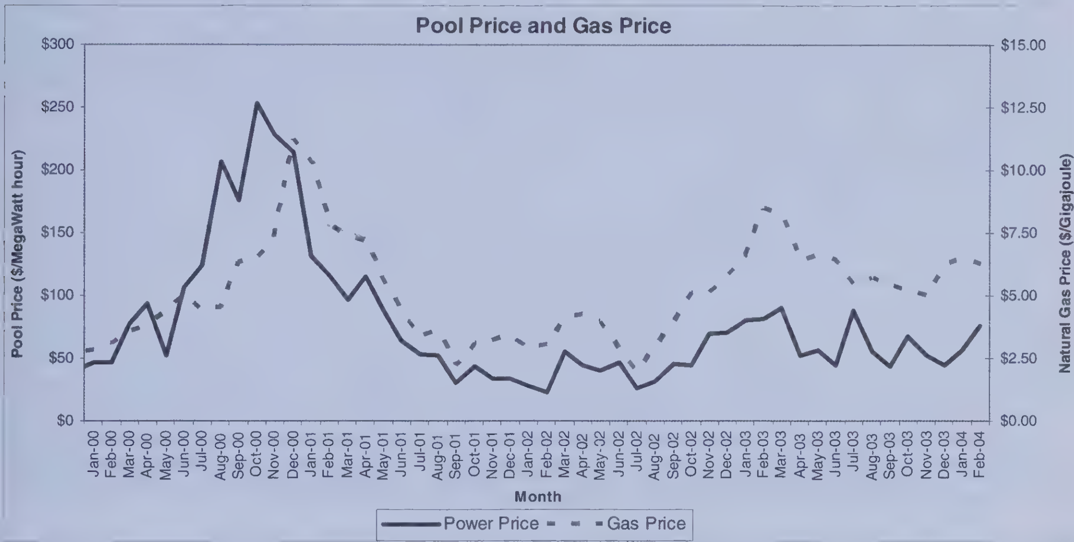
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2003, sales from approximately 66% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 34% consisted primarily of sales to the AESO. In 2004, the portion of generating capacity subject to long term agreements is expected to be approximately 74%, while the remaining 26% is expected to consist primarily of sales of electricity to the AESO. These sales are dependent on prices in the Alberta electricity spot market. The majority of the electricity sales to the AESO are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a strong correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Electricity prices and natural gas prices can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2004.



Changes in AESO prices and gas prices may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) Equity contributions – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $35.3 million.

b) Completion of construction – Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is $161.2 million, with an expiry date of September 30, 2006.

c) Project cash flows – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts for the Scotford project and 48 megawatts for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2003, $0.4 million was payable for the Muskeg River and Scotford projects.

d) Reserve amounts – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities

Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2003, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
	($ Millions)	
ATCO Power Alberta Limited Partnership ("APALP") project financing........	Nil (1)	6.7
Joffre project financing	Nil (2)	4.8
Muskeg River project financing	Nil (1)	5.3
Scotford project financing	Nil (1)	5.3

Notes:
(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $1.4 million met with project cash flows.

e) Prepaid operating and maintenance fee – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2003, the maximum value of the guarantee is $33.6 million.

f) Purchase project assets – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2003, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. Canadian Utilities Limited has guaranteed ATCO Power's obligation to remediate certain deficiencies at the Oldman River project in the amount of $2.4 million. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory Project.

ATCO Power (80%) and ATCO Resources Ltd. (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects. The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. Management is confident that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to $167.5 million at December 31, 2003. This balance includes $46.3 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to $121.2 million, is expected to be recovered from utility customers through inclusion in future rates. There are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2007. In addition, the Corporation uses various derivative instruments to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. Note 19 to the financial statements sets out the instruments in place at December 31, 2003.

Other than the foregoing, the Corporation does not have any off-balance sheet arrangements that have, or are likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

Deferred Availability Incentives

As noted previously in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2003, the Corporation had recorded $43.3 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.5 million in 2003.

The amount of deferred availability incentives to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast best case, worst case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues, the best case scenario would have resulted in higher revenues of approximately $4.0 million, whereas the worst case scenario would have resulted in lower revenues of approximately $3.5 million.

Employee Future Benefits

The Corporation's employee future benefits disclosures are based on three critical accounting estimates: (1) the expected long term rate of return on plan assets; (2) the liability discount rate; and, (3) the long term inflation rate.

The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 6.5% at the beginning of 2003, resulted in an expected long term rate of return of 7.5% for 2003. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

The liability discount rate reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate used to calculate the cost of benefit obligations in 2003 was 6.5%; the liability discount rate used to determine the accrued benefit obligations at the end of 2003 was reduced to 6.25%.

The expected long term rate of return has declined over the past two years, from 8.1% in 2001 to 7.5% in 2003. The result has been a decrease in the expected return on plan assets. The difference between the expected return and the actual return on plan assets results in an experience gain or loss on plan assets. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 6.25% at the end of 2003. The effect of this change has been to increase the accrued benefit obligations, resulting in experience losses in 2002 and 2003. In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the cumulative experience losses in 2003 for both pension benefit plans and other post employment benefit plans.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 10.5% for 2003 grading down over 10 years to 4.5%, and for other medical and dental costs, 4.0% for 2003 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AEUB decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan expense (income) for 2003 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2003 Pension Benefit Plans		**2003 Other Post Employment Benefit Plans**	
	Accrued Benefit Obligation	**Benefit Plan Expense (Income)**	**Accrued Benefit Obligation**	**Benefit Plan Expense (Income)**
	($ Millions)			
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.5)	-	-
1% decrease (1)	-	3.5	-	-
Liability discount rate				
1% increase (1)	(52.2)	(0.3)	(2.8)	(0.3)
1% decrease (1)	52.2	0.3	2.8	0.3
Long term inflation rate (2)				
1% increase (1)	34.6	0.5	2.6	0.5
1% decrease (1)	(34.6)	(0.5)	(2.2)	(0.4)

Notes:

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans expense (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for other post employment benefits plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2004, the Corporation will retroactively adopt the recommendations of the Canadian Institute of Chartered Accountants ("CICA") on stock based compensation. The recommendations require expensing of stock options. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

Effective January 1, 2004, the Corporation will retroactively adopt the recommendations of the CICA on accounting for asset retirement obligations. The recommendations require total retirement costs to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

Effective January 1, 2004, the Corporation will prospectively adopt the recommendations of the CICA on accounting for asset impairment. The recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in income when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

During 2003, the Corporation adopted the CICA's accounting guideline pertaining to the identification, designation, documentation and effectiveness of hedging relationships for the purposes of applying hedge accounting.

February 25, 2004

Consolidated Five-Year Financial Summary

(Millions of Canadian dollars, except as indicated)		**2003**	2002	2001	2000	1999
EARNINGS						
Revenues		**3,742.6**	2,975.9	3,513.6	2,924.5	2,209.4
Operating expenses		**2,868.7**	2,170.5	2,696.3	2,088.7	1,427.4
Depreciation and amortization		**268.9**	244.4	241.9	238.9	229.6
Interest		**190.3**	184.1	198.7	196.2	182.2
Dividends on preferred shares		**-**	-	-	0.6	6.6
Interest and other income		**(33.4)**	(136.2)	(41.4)	(23.5)	(23.5)
Income taxes		**155.7**	189.9	164.0	179.4	172.1
Dividends on equity preferred shares		**33.1**	18.2	17.0	16.8	14.9
Earnings attributable to Class A and Class B shares		**259.3**	305.0	237.1	227.4	200.1
SEGMENTED EARNINGS						
Utilities		**97.7**	147.7	73.9	77.2	92.4
Power generation		**92.7**	75.3	94.7	96.5	67.2
Logistics and energy services		**60.8**	64.4	51.5	46.8	40.7
Technologies and other businesses		**19.1**	11.1	8.9	6.3	3.4
Corporate/eliminations		**(11.0)**	6.5	8.1	0.6	(3.6)
Earnings attributable to Class A and Class B shares		**259.3**	305.0	237.1	227.4	200.1
BALANCE SHEET						
Property, plant, and equipment		**4,809.4**	4,657.0	4,363.5	4,007.4	3,848.0
Total assets		**6,070.5**	5,934.4	5,404.0	5,403.9	4,538.5
Capitalization:						
Notes payable		**-**	-	4.6	197.1	80.7
Long term debt		**1,805.3**	1,916.9	1,855.9	1,865.5	1,716.2
Non-recourse long term debt		**806.1**	821.1	673.8	360.0	395.4
Preferred shares		**-**	-	-	-	50.0
Equity preferred shares		**636.5**	486.5	336.5	336.5	320.6
Share owners' equity*		**1,951.6**	1,830.1	1,643.8	1,526.5	1,419.0
Total capitalization		**5,199.5**	5,054.6	4,514.6	4,285.6	3,981.9
CASH FLOWS						
Operations		**525.8**	504.6	532.2	490.2	465.2
Purchase of property, plant and equipment		**495.7**	569.8	735.3	451.3	367.3
Financing (excluding Class A and B dividends)		**(10.6)**	384.3	62.0	189.5	39.8
Class A and B dividends		**129.3**	124.2	119.0	114.0	109.0
CLASS A & B SHARES						
Shares outstanding at end of year* (thousands)		**63,384**	63,412	63,317	63,306	63,349
Return on equity*		**13.7%**	17.6%	15.0%	15.4%	14.5%
Earnings per share* ($)		**4.09**	4.81	3.74	3.59	3.16
Dividends paid per share* ($)		**2.04**	1.96	1.88	1.80	1.72
Equity per share* ($)		**30.79**	28.86	25.96	24.11	22.40
Stock market record - Class A non-voting shares ($)	High	**59.60**	60.10	56.05	51.45	49.35
	Low	**45.10**	48.80	44.50	31.00	32.35
	Close	**57.86**	51.21	49.75	51.00	39.00
Stock market record - Class B common shares ($)	High	**58.75**	60.50	54.20	51.15	49.25
	Low	**45.50**	49.00	44.95	31.10	32.50
	Close	**58.00**	52.65	49.00	50.55	39.25

* Includes Class A non-voting shares and Class B common shares.

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	**2003**	2002	2001	2000	1999
Utilities					
Natural gas operations					
Purchase of property, plant and equipment	**141.0**	103.1	84.6	87.6	86.9
Pipelines (thousands of kilometres)	**34.2**	33.7	33.5	33.5	33.0
Maximum daily demand (terajoules)	**1,831**	1,670	1,470	1,737	1,595
Sales (petajoules)	**198**	201	187	209	192
Transportation (petajoules)	**32**	31	22	18	13
Total system throughput (petajoules)	**230**	232	209	227	205
Average annual use per residential customer (gigajoules)	**134**	136	131	148	138
Degree days - Edmonton *	**4,245**	4,274	3,661	4,210	3,774
- Calgary **	**4,291**	4,470	3,994	4,441	3,869
Customers at year-end (thousands)	**887.8**	862.0	837.7	816.1	798.4
Electric operations					
Purchase of property, plant and equipment	**173.3**	171.4	154.3	114.5	101.2
Power lines (thousands of kilometres)	**67.0**	67.1	64.2	58.6	57.9
Retail sales (millions of kilowatt hours)	**9,768**	10,224	10,108	10,392	10,068
Average annual use per residential customer (kWh)	**7,261**	7,445	7,270	7,444	7,367
Customers at year-end (thousands)	**202.3**	197.8	192.0	191.0	186.8
Power Generation					
Purchase of property, plant and equipment	**131.7**	236.0	384.2	155.5	119.8
Generating capacity (thousands of kilowatts)	**2,397**	2,036	2,036	668	514
Logistics and Energy Services					
Purchase of property, plant and equipment	**37.5**	48.9	101.9	84.7	51.4
Pipelines (thousands of kilometres)	**8.3**	8.3	8.2	7.9	7.9
Contract demand for pipelines system access (terajoules/day)	**4,599**	4,890	4,876	4,559	4,378
Natural gas processed (Mmcf/day)	**399**	420	429	366	332
Natural gas gathering lines (kilometres)	**1,000**	940	940	670	500

* Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.

** Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

GENERAL INFORMATION

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Wednesday, May 12, 2004 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A Non-Voting and
Class B Common Shares and
Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/Calgary/Vancouver

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU
Class B common Symbol CU.X
Listing: The Toronto Stock Exchange

CUMULATIVE REDEEMABLE SECOND PREFERRED SHARES
5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:
ATCO Ltd. & Canadian Utilities Limited
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.canadian-utilities.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:
CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
Telephone: 1-800-387-0825
e-mail: inquiries@cibcmellon.com
Website: www.cibcmellon.com

Printed in Canada

Canadian Utilities Limited
1400, 909 – 11th Avenue SW, Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Fax: (403) 292-7623

www.canadian–utilities.com